

**BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN**

Application of American Transmission Company LLC, as an Electric Public Utility, for a Certificate of Public Convenience and Necessity to Construct a New 138 kV Transmission Line from the Howards Grove Substation to the Erdman Substation located in Sheboygan County, Wisconsin

Docket No. 137-CE-195

AFFIDAVIT OF CHRISTOPHER ZIBART

I, CHRISTOPHER ZIBART, being first duly sworn on oath, depose and state, as follows:

1. I am an employee of ATC Management Inc. I hold the position of Deputy General Counsel, and I am authorized to sign this affidavit on behalf of American Transmission Company LLC, and its corporate manager, ATC Management Inc. (collectively "ATC").

2. This request for confidential handling is made on behalf of ATC, the corporate headquarters of which is at W234 N2000 Ridgeview Parkway Court, Waukesha, Wisconsin.

3. ATC has filed its application to the Public Service Commission of Wisconsin ("Commission") for the Howards Grove to Erdman Project ("Project"). The Project consists of a new 138kV transmission line and several other system upgrades.

4. To assess the need for the Project, ATC has conducted analyses of its system. The subject of ATC's request for confidential handling contains the following:

- The revised project scoping document.

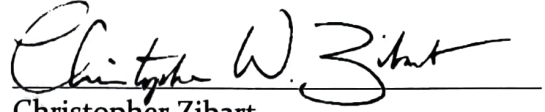
5. Certain items of the technical information in the document, could be used to find weaknesses in ATC's transmission system. These could therefore be useful to someone planning an attack on ATC's critical energy infrastructure, and the information goes beyond the physical location of the facilities. Information of this type is considered Critical Energy Infrastructure Information ("CEII") under federal law, and ATC is bound to protect it. FERC Orders No. 630, 68 Fed. Reg. 9857 (2003), and No. 683, 71 Fed. Reg. 58,273 (2006); 18 C.F.R. § 388.113. ATC has adopted a procedure entitled "Identification and Protection of CEII Materials" consistent with these legal requirements and has determined that the information on the discs includes CEII. In accordance with this procedure, ATC has labeled the discs as containing CEII.

6. Holding confidential the presently submitted information describing certain details of the electric transmission system supports the public interest in continued protection of the physical security of the electric transmission system and in maintaining a fair and competitive wholesale electric market that does not favor any particular market participant. Disclosure of this information may lead to the harm and diminishment of secure, equitable, and competitive energy markets in the State of Wisconsin.

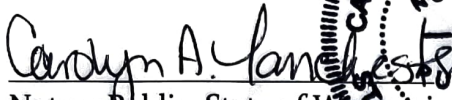
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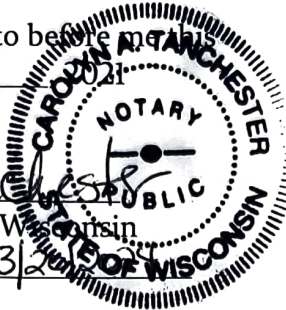
8. ATC is providing this information to facilitate the Commission's review of the need for the Project and that ATC's plans to address these energy needs are in the public interest.

9. The above and foregoing is true and correct to the best of my personal knowledge and belief.


Christopher Zibart
Deputy General Counsel

Subscribed and sworn to before me on this
4th day of August 2011


Notary Public, State of Wisconsin
My Commission ends: 3/25/2015





HOWARDS GROVE-ERDMAN 138 KV LINE

Project Scoping Document

Planning Zone: 4

Version 1

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System Planning

April 26, 2021

Critical Energy Infrastructure Information (CEII)

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1. Executive Summary

The Howards Grove – Erdman area project consists of the following:

- New Howards Grove – Erdman 138 kV line, and
- Expansion of Howards Grove 138 kV straight bus into a 4-position ring bus.

This study will show that there are reliability issues that need to be addressed with the Edgewater generation in service. Considering the age and fuel type of the Edgewater Power Plant, the likelihood of this generation being retired in the near future will aggravate the existing reliability issues and will create new reliability issues. This study shows even if Edgewater Power Plant remains, the proposed project will address several reliability issues and will provide operational benefits.

As a result of the planned retirement of the Edgewater Power Plant, this area was studied using a bookend approach: one scenario with Edgewater modeled off-line, and one scenario with it modeled online. If the Edgewater Power Plant is retired as planned, one of the main assumptions for this study is that no replacement generation will be developed at or near the Edgewater site.

In addition to addressing reliability concerns, implementation of the proposed project will provide several benefits to ATC customers. Compared to alternatives, this project provides flexibility to address the potential for area generation or load changes at the lowest cost. In addition, this project removes the need for system reconfiguration in the area and reduces energy losses. These benefits, in combination with the cost of the project, support the proposed project as the preferred project to address identified reliability needs.

The study area consisted of the facilities in Sheboygan County and possesses unique characteristics contributing to the need for increased transmission facilities. There are limited 345 and 138 kV connections into the Sheboygan area. Another characteristic is this area experiences relatively high loads during traditional non-peak hours due to a large load [REDACTED] hours a day. This makes it more difficult to find times of the year to schedule generation and transmission system maintenance. A third characteristic is the decreasing availability of generating capacity within the area, for example the potential to retire the remaining Edgewater generation.

ATC currently utilizes a process to reconfigure the system to address system limitations related to the planned or forced outage of any one of the following 138 kV lines:

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

When any one of these lines is out for maintenance, a High-Risk Mitigation Plan is implemented such that all Sheboygan area load (~150-230 MW) is lost in the event of a second 138 kV outage in the area. Radializing the system after the first planned or forced outage prevents unacceptable operating conditions (in the form of voltage instability) in the event of a second outage, but also assures load loss for the second outage.

If the Edgewater Power Plant is retired as planned, load, generation and transmission capability in the planning study area become even further out of balance. This imbalance drives an increased reliability need for system reinforcements within the planning study area.

Two system alternatives were evaluated to address these limitations. Alternative #1 (Preferred) involves the construction of a new Howards Grove – Erdman 138 kV line and associated substation upgrades. Alternative #2 involves the construction of a new Plymouth – Erdman 138 kV transmission line and associated substation upgrades. Refer to Section 4 for additional details on the proposed scope of the alternatives.

Both alternatives address the reliability issues described. The preferred alternative is less expensive than the other alternative.

To address the potential for voltage instability, the in-service date of this project is needed prior to the retirement of Edgewater Power Plant. The aggressive 2023 in-service date was chosen due to the urgent need to align as closely as possible with the generation retirement date. The capital cost of the preferred project outlined in this document is estimated to be approximately \$21.6 million in 2023 dollars and includes the cost to accelerate in-service date. This estimate is a planning-level cost estimate developed for the purpose of comparing the cost of the alternatives. This cost estimate may change as the routing and siting of the project progresses. A Project Diagram for the proposed project can be found in Appendix D.

When all factors have been considered, the proposed project scope is the best system alternative to address area needs while providing flexibility for future uncertainties.

2. Introduction

The purpose of this project scoping document is to define the planning study area, document background information about the existing electric system, analyze and document the need for the proposed project, describe the alternatives considered, discuss why the preferred alternative was selected, outline the scope of the preferred project and discuss other considerations that need to be addressed at this time.

3. Project Need

As described in further detail in the remainder of this section, potential for unacceptably low voltages and voltage instability under the mandatory NERC TPL-001-4 reliability standards drives the need for a reinforcement project in the planning study area. This NERC standard can be broken down into two basic categories: contingency categories that do not allow loss of load and contingency categories that allow loss of load. For further details regarding these categories, refer to Section 3.2.

The Edgewater Power Plant is scheduled to be retired in the year 2022. As a result, the area was studied with the Edgewater Plant retired in one scenario, and online in a second scenario. Additional

considerations for determining project need include the mandatory NERC TPL standards, chronic operating issues, the ability to perform maintenance on our equipment and projected load growth.

3.1 Study Area Reliability Considerations

The purpose of this section is to present and document the need for transmission system reinforcement by presenting results of recent planning studies, identifying unique load and generation characteristics, describing planned asset management projects, and providing a high-level summary of existing Special Protection Systems, Operating Guides and System Control Operator (SCO) Reference Guides within the planning study area. Examination of this information indicates that the planning study area has deficiencies that will clearly require transmission system reinforcements.

3.1.1 Transmission System Characteristics

The planning study area outlined in Appendix B includes Sheboygan County in eastern Wisconsin and surrounding areas. This area has some unique characteristics that contribute to the need for increased transmission facilities.

The transmission system in the Sheboygan area includes two parallel 138 kV paths that traverse south-to-north through the city from the Edgewater Substation. Edgewater Substation is located to the south of the greater Sheboygan area. The Edgewater-Sauk Trail-20th Street-Erdman 138 kV path is located on the east side of the city and the Edgewater-Lodestar-Erdman 138 kV path is located on the west side of the city. The largest load in the Sheboygan area [REDACTED], which has historically operated at an 83% power factor. There is one additional 138 kV circuit (Mullet River-South Sheboygan Falls-Edgewater 138) tying the Sheboygan area to the rest of the transmission system.

[REDACTED]

The primary generating unit modeled in this area is the Edgewater Power Plant, of which only Unit #5 remains. Units #3 and #4 were retired within the last five years, and Unit #5 is scheduled to be retired in the year 2022. Other units were retired many years ago.

As previously discussed, it has traditionally been difficult to perform maintenance in this area due to the lack of acceptable windows of time. All BES elements must be taken out of service for maintenance at set intervals for certain periods of time. For maintenance planning purposes, maintenance windows are typically at least two to four weeks long. Additionally, ATC assumes maintenance windows have continuous hours below a given load level. The reasons why ATC prefers the availability of a large window of hours to perform required transmission and generator maintenance are as follows:

- scheduled maintenance can be impacted by inclement weather,
- higher than expected temperatures may delay the availability of the requested outages,

- there are a number of generation and transmission facilities that require periodic maintenance; many of these maintenance outages cannot be overlapped because of the decreased reliability of the system during these outages. Thus, ATC needs to target multiple two- to four-week windows in which maintenance can be performed,
- due to the variability of prior and competing outages, they can occur within the same timeframe,
- total number of hours available for maintenance in the future is uncertain due to load forecast variability and generation availability,
- generator maintenance outages typically require longer timeframes and can periodically be offline for an eight- to nine-week scheduled outage.

It has become increasingly difficult to schedule maintenance within the planning study area. Figures 3.1 through 3.5 more fully illustrate this issue. As shown in Figure 3.1, the daily peaks within the ATC footprint are typically around 70% on average, providing sufficient availability to perform maintenance on the system overall when the load is at or below this level. At this load level, it appears that there are many opportunities available in which maintenance can be scheduled and performed.

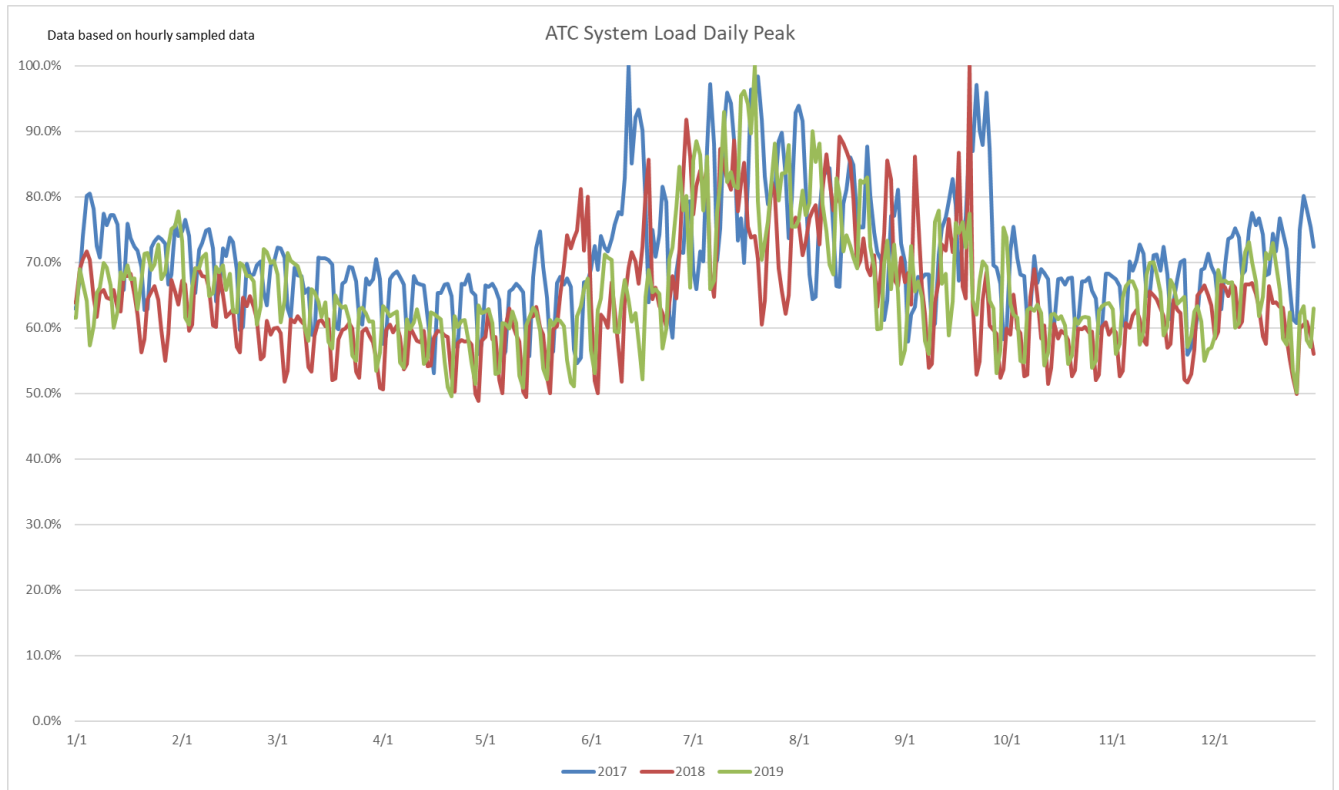


Figure 3.1: ATC System Daily Peak Loads (2017 – 2019)

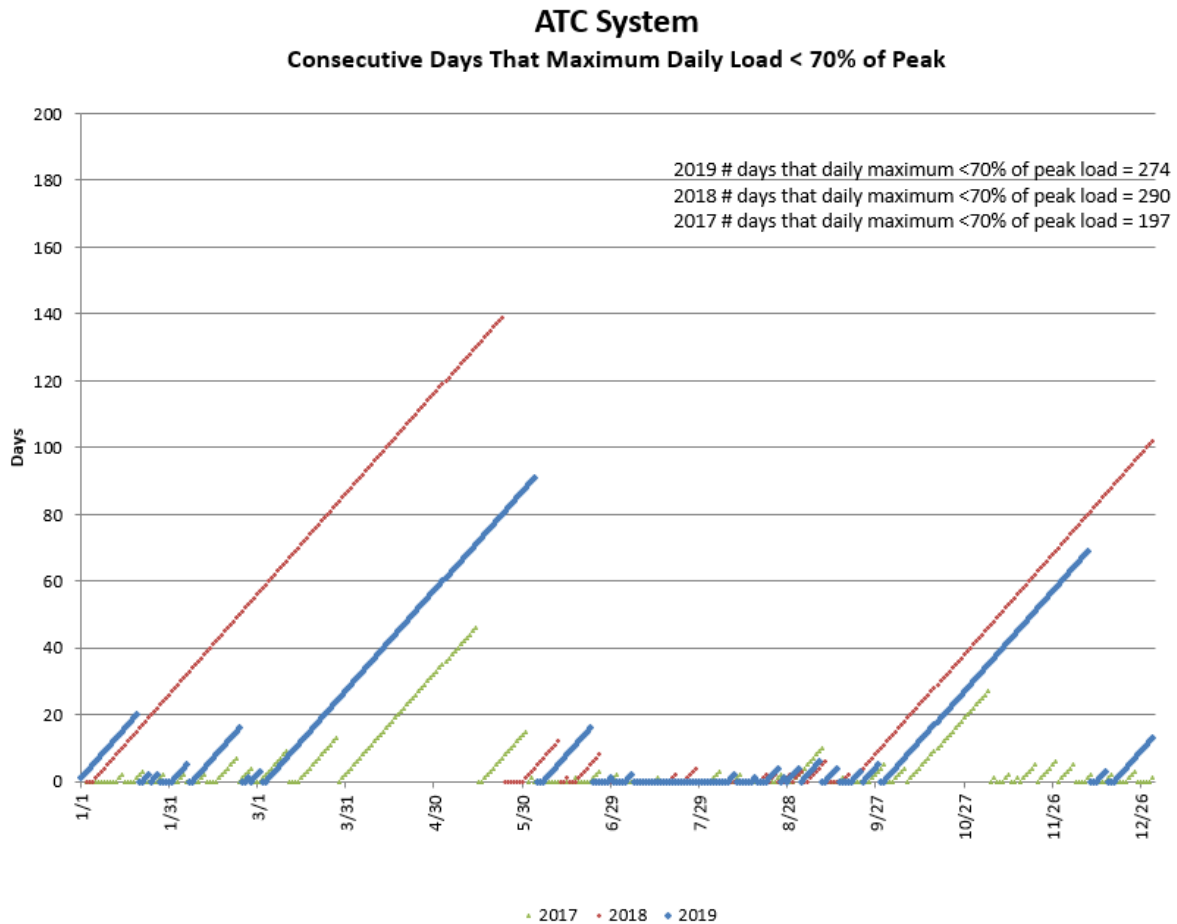


Figure 3.2: ATC System, Consecutive Days Daily Maximum < 70% of Peak

Figure 3.1 shows the daily peaks without taking into account whether there are blocks of time with consecutive days below the 70% load level traditionally targeted for performing maintenance. Figure 3.2 takes this methodology a step further and illustrates the number of consecutive days below the targeted 70% load level that provide appropriate margins to perform maintenance work. For example, the 2019 data (blue line) shows there are approximately 90 consecutive days from the beginning of March to late May where the ATC system daily peak load does not exceed 70% of its yearly peak, and another 70-day window of time from mid-September until December. The figure also shows few if any consecutive days available during the summer months. Figure 3.2 indicates that there are adequate blocks of consecutive days available in which to perform maintenance activities on the ATC system as a whole.

As shown in Figure 3.3, the daily peaks within the planning study area are variable in nature as compared to the ATC system as a whole.

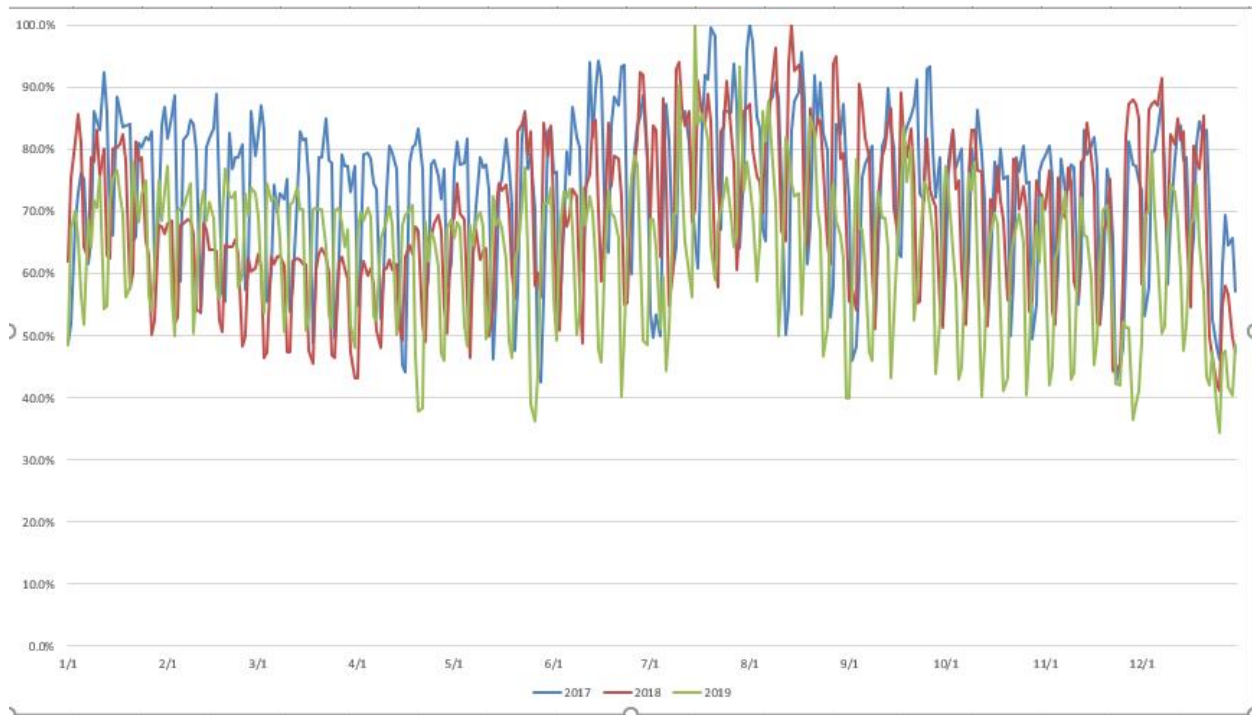


Figure 3.3: Planning Study Area Daily Peak Loads

Figure 3.3 shows the daily peaks for the study area, without considering whether there are blocks of time with consecutive days below the load level that is needed for performing maintenance. Figure 3.4 illustrates the number of consecutive days below the 70% load level available to perform maintenance work. This figure illustrates that there are virtually no blocks of consecutive days available in which to perform maintenance activities. Note that the 2018 data (red line) is an outlier because the majority of a large customer's load was offline during those months as a result of a fire.

That said, even in 2018, there was only one block of time available to perform maintenance early in the year. There were no acceptable blocks of time available to perform maintenance in 2017 or 2019.

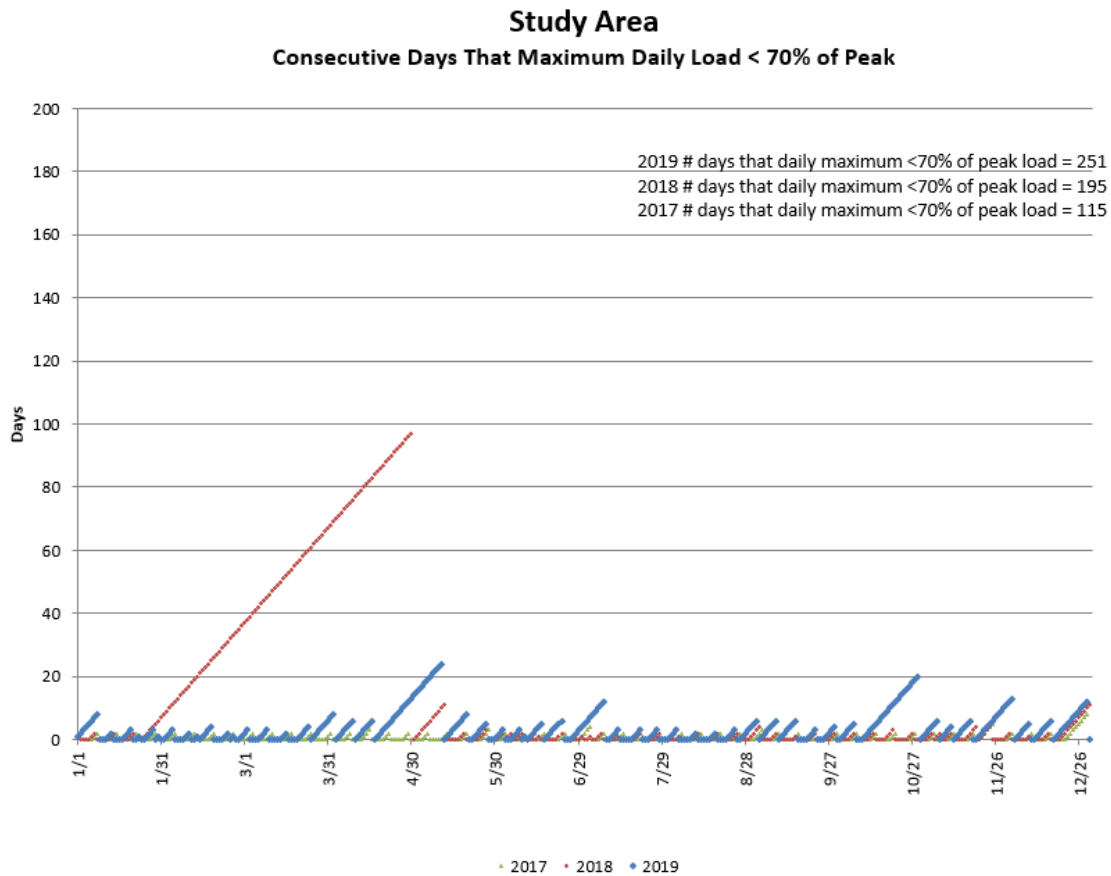


Figure 3.4: Planning Study Area, Consecutive Days Daily Maximum < 70% of Peak

ATC typically looks for maintenance windows at the 70% load level, and as Figure 3.4 clearly shows, there are few to no windows of availability. This highlights the variability and uncertainty inherent to performing maintenance within the planning study area within any given year. This is one of the reasons why, in the Planning timeframe, two- to four-week windows are targeted for these maintenance periods.

The above figures support the conclusion that ATC currently has no windows of time to perform required maintenance of its equipment during the traditional 70% load level within the planning study area. When lining up the required transmission and generation maintenance outages, ATC sees that the availability of adequate maintenance windows in this area has been problematic in the past and will continue to be challenging going forward.

The planning study area was chosen to include the area with the unique load and generation characteristics as described above.

3.1.2 Recent Planning Studies

The most recent significant ATC planning study conducted within the planning study area was to determine area needs related to the Edgewater 345 kV reconfiguration planned in the 2022-2024 timeframe.

The Edgewater reconfiguration study effort identified proposed reinforcement projects due to the potential for voltage instability during scheduled maintenance. In order to perform this long-duration maintenance, several voltage improvements in the area were identified:

- [REDACTED]: improve power factor from 83% to at least 90% (2020),
- New Huebner: 2-8.16 MVAR capacitor banks (2021), and
- New 20th Street: 2-8.16 MVAR capacitor banks (2021).

Even with these capacitor banks and power factor improvements assumed in service, the area will require further reactive compensation in the form of mobile capacitor banks in order to complete the reconfiguration project without compromising the system.

In 2019, ATC personnel [REDACTED] about the low power factor. As a result, [REDACTED] use capacitor banks that they had available on site in order to improve their voltage profile. In the summer of 2019, [REDACTED] their capacitor banks and it made a pronounced difference in their power factor. However, turning on the banks created harmonic issues on their system, and they subsequently de-energized the unit. ATC is continuing discussions with [REDACTED] in order to determine if the harmonics issues can be resolved.

This planning study assumes that the [REDACTED] power factor improvement to at least 90% and installation of 20th Street and Huebner capacitor banks are complete and in-service.

3.1.3 Loads and Forecasts

As shown in Figure F.1 of Appendix F, based on the 2019 coincident peak forecast information from the LSEs (load serving entities), the forecasted load growth rate within the planning study area is 0.2% for 2021-2030. This compound growth rate is developed directly from the data received from the load distribution companies and does not consider any potential variability of loads or generation within the planning study area. Additionally, the calculation of this growth rate is entirely forecast dependent and is not based upon a historical starting point. Figure F.1 depicts the coincident load forecasts received from the LSEs from 2019 through 2021 as well as historical coincident data through 2020.

The load forecast used in these studies was the forecast received from each LSE within ATC's footprint in 2018. This forecast was used during the 2019 ATC 10-Year Assessment. A comparison of the 2019, 2020 and 2021 forecasts for the planning study area against the most recently submitted load forecasts by each LSE shows that they are comparable, without a significant enough change to warrant a restudy of the planning study area needs.

While there isn't much load growth in the area, changes in area resources while attempting to serve and maintain the existing area load during outage conditions are driving the need for a project, even when the Edgewater Power Plant remains online. Load growth is not a need driver for this project.

3.1.4 Generation

The key generation in the planning study area includes:

- Edgewater unit #5 in Sheboygan, WI

3.1.4.1 Edgewater

Edgewater previously had three generating units available (units #3, 4 and 5). Coal-fired generator units #3 and #4 (69 MW and 351 MW) were retired in 2015 and 2018, respectively. Existing coal-fired unit #5 was placed in service in 1985, and Alliant Energy has announced that the 413.7 MW generator will be retired in the year 2022. Thus, this study was run as two sets of models: one set with Edgewater retired, and one set with Edgewater assumed online.

The Edgewater Power Plant is a significant resource for the Sheboygan area, and it helps support voltage and local reliability. The power flow studies highlighted in Section 3.2 and Section 3.3 demonstrate the importance of Edgewater to the Sheboygan area.

3.1.4.2 System Stability Summary

Voltage stability simulations (VSAT) will be performed for both Needs and Solution Development studies for voltage instability verification and alternative performance verification. These stability results are presented in Section 4 of this document.

Angular generator stability issues currently exist which are related to the limited number of transmission ties between the Edgewater Power Plant and the transmission system in Wisconsin. The long-term status of the Edgewater unit is uncertain at this time, and appropriate angular stability studies will be performed, if needed, prior to submission of the CPCN. If the generator is retired as planned, angular stability studies will not be required.

3.1.5 Asset Management Considerations

To the extent that alternatives affect portions of ATC system that have major asset renewal plans these are being considered in the development of the alternative solutions. As alternative solutions are scoped these are being reviewed by a cross-functional team to make sure proposed asset renewal projects are taken into consideration.

The more significant Asset Renewal projects under consideration in the general area of the proposed alternative include the following:

- Edgewater 345 kV reconfiguration (2022-2024)
- Erdman 138/69 kV transformer replacement (2022)
- X-48/Y-31 underground line rebuilds (2023)

It is likely that the Erdman transformer and the X-48/Y-31 underground line rebuild projects will move forward regardless of the resolution of Edgewater unit #5. The Edgewater 345 kV reconfiguration project is moving forward as a 4-position ring bus but could change depending upon the resolution of Edgewater unit #5.

3.1.6 Standing Special Protection Systems and Operating Guides

There are no Special Protection Systems or Operating Guides in the area. However, there is a process in place that ATC Operators use to reconfigure the Sheboygan area in the event of a planned or forced outage, which is the following:

In the event of a maintenance or forced outage of any one of the following lines:

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

The breaker on the [REDACTED]. The net effect is that should another outage happen within this area, load will be dropped as a result of that outage. If that occurs, voltage instability is avoided.

This provides operators with an option to support planned or forced outages by reconfiguring the Sheboygan area after [REDACTED] in the area to prevent voltage instability in the event of a second outage. The existence of this plan highlights a potential reliability risk in the area and can be considered one of the need drivers to be addressed in the solution development process.

3.2 Power Flow Analysis

The contingency analysis was performed on the study-specific models as described in the Appendix A of this document. The system alternatives discussed in this document were not included in the models for the power flow needs analysis conducted in this section. ATC used steady state and dynamic simulations to assess the impacts of NERC Standard TPL-001-4 at voltage levels 69 kV and above.

The NERC TPL-001-4 reliability standard states that the transmission system shall be assessed under various system normal and contingency conditions. ATC Planning Criteria version 19.4 generally states that under system normal conditions (NERC Cat. P0) all voltages must remain between 0.95 per unit and 1.05 per unit and all facility loadings must remain below their normal ratings. Additionally, ATC Planning Criteria generally states that under contingency conditions (NERC Cat. P1 – P7) all voltages must remain between 0.90 per unit and 1.10 per unit and all facility loadings must remain below their 2-hour emergency ratings.

The starting power flow models utilized in this study are from the MISO MTEP 2019 series, and are as follows:

- MISO19_2024_SH40__TA_Final.sav (2024 shoulder model)
- MISO19_2024_SUM__TA_Final.sav (2024 summer peak model)
- MISO19_2029_SUM__TA_Final.sav (2029 summer peak model)

It is outlined in the Interconnection Guide that ATC's customers shall generally plan, design and maintain their load interconnection facilities in order to maintain a 95% lagging power factor at the low side of

the load interconnection transformer. ATC performed analysis to determine the amount of power factor improvement needed at [REDACTED] to improve the study area's voltage profile. ATC's analysis shows that improvement of the [REDACTED] power factor from 83% to 90% or above will improve the voltage profile in the area enough to provide some relief. [REDACTED] and ATC are working together to ensure that the 90% power factor is maintained.

The starting models were adjusted by turning off Edgewater Unit #5, adding the Edgewater Distribution T-D project (~13 MW load shift at peak), adjusting the [REDACTED] power factor to 90%, and adding the Huebner and 20th Street capacitor banks.

3.2.1 NERC TPL Contingency Categories That Do Not Allow Loss of Load

NERC TPL-001-4 contingency categories that do not allow loss of load include the following for facilities 100 kV and above (unless otherwise noted):

- P0 – all facilities in service
- P1 – event resulting in the loss of a single element (generator, transmission circuit, transformer, shunt device, single pole of a DC line)
- Prior maintenance of facility plus a P1 event, at off-peak load level only
- P2 – event resulting in the loss of a single element (opening a line section without a fault, EHV bus section fault, EHV non-bus tie breaker fault)
- P3 – loss of generator unit followed by system adjustments, followed by Category P1 event
- P4 – for steady state power flow simulations, P4 EHV defined contingencies are covered by P2s.
- P5 – for steady state power flow simulations, P5 EHV defined contingencies are covered by P2s.

Specifically, system reinforcement is required if any one of the following conditions is met:

- 30-minute emergency ratings are exceeded for any length of time,
- Two-hour emergency ratings are exceeded and cannot be mitigated below acceptable limits within 30 minutes,
- Voltages are below 0.9 per unit and cannot be mitigated by using automatic adjustments, or
- Voltages are above 1.1 per unit and cannot be mitigated by using automatic adjustments.

Instability, cascading, or voltage and flows outside appropriate limits resulting from the above contingency definitions would generally drive the need to develop a solution option. Planning to shed load is not an acceptable mitigation procedure.

For further details regarding contingency types, please refer to Appendix A, Table A.1.

3.2.1.1 Edgewater Generation Retired Scenario, 2024 Summer Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.2.1.2 Edgewater Generation Retired Scenario, 2024 Off-Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions, including prior maintenance plus single Category P1 outage within the study area, the following is a summary of the study results:

- No system overloads, and
- Twelve prior maintenance plus Category P1 combinations resulted in extremely low voltages (<0.8 per unit), indicating the potential for voltage instability as shown in Figure 3.5.
 - The most load that ATC could serve would be 129 MW (blue line in Figure 3.5) to eliminate voltage instability for the prior maintenance of [REDACTED]. For 3,700 hours of the year, potentially all the study area load is at risk, which equates to approximately 42% of the time. The amount of load at risk varies depending upon the amount of load online at the time of contingency and could be as much as the total study area peak load of 210-230 MW.
 - The most load that ATC could serve would be 117 MW (red line in Figure 3.5) to eliminate low voltages for this contingency. For 6,000 hours of the year, potentially all study area load is at risk, which equates to approximately 68% of the time. The amount of load at risk varies depending upon the amount of load online at the time of contingency and could be as much as the total study area peak load of 210-230 MW.
 - Please refer to Section 3.5, Figure 3.5.2 for the simulations indicating voltage instability and unacceptably low voltages for this scenario.

The below load duration curve indicates MW values on the vertical axis and hours on the horizontal, for each of the three years 2017 through 2019. As shown, the load duration curves for each year are virtually identical.

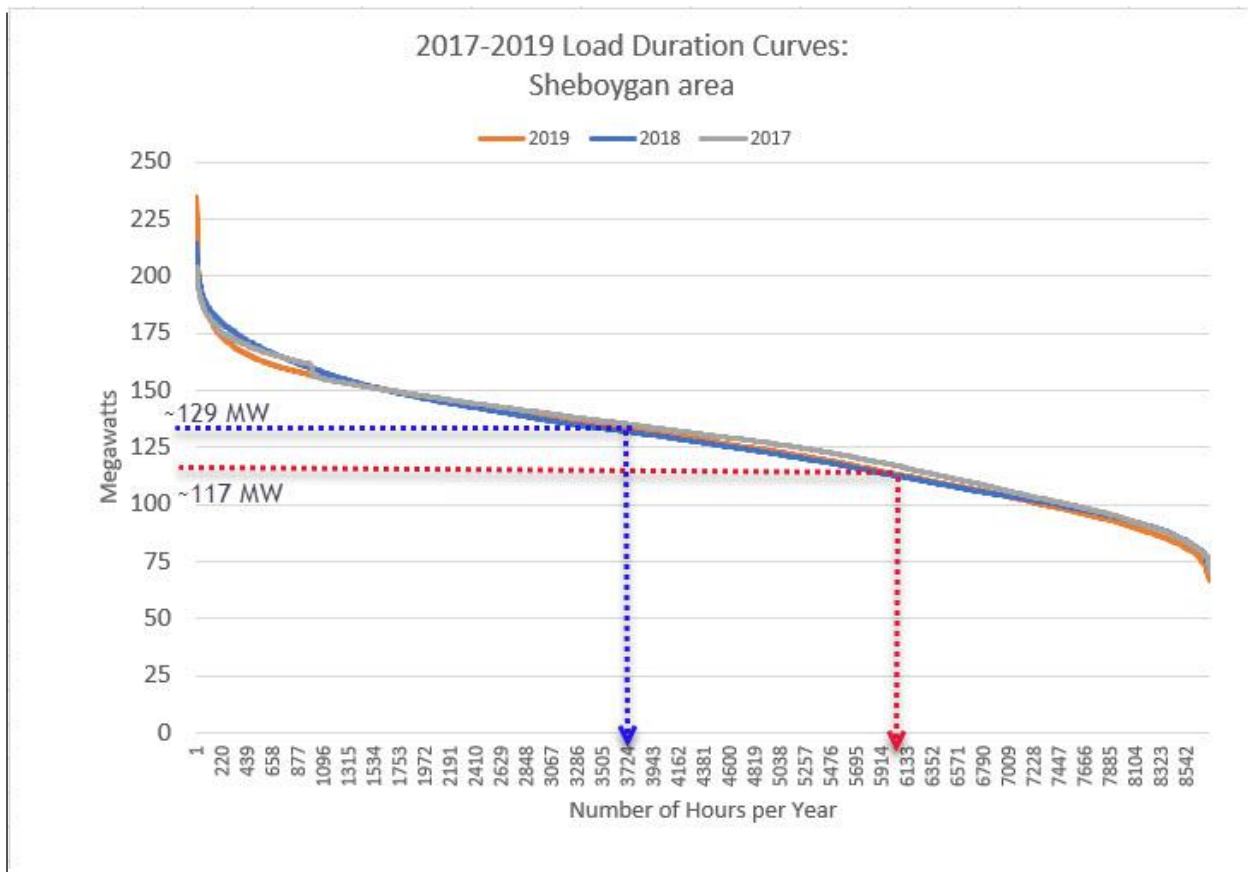


Figure 3.5: Study Area Load Duration Curves: Prior Maintenance Plus Single Category P1 Outage

Extending the blue-dashed line (~129 MW on the vertical axis) from any one of the curves on Figure 3.5 to the horizontal axis indicates that in order to avoid voltage instability for a single event during a maintenance outage, approximately 42% of the time, or 3,700/8760 hours, load would need to be shed pre-contingent in order to avoid voltage instability.

Similarly, extending the red-dashed line (~117 MW on the vertical axis) from any one of the curves on Figure 3.5 to the horizontal axis indicates that in order to avoid unacceptably low voltages for a single event during a maintenance outage, approximately 68% of the time, or 6000/8760 hours, load would need to be shed pre-contingent in order to avoid the low voltage condition.

3.2.1.3 Edgewater Generation Retired Scenario, 2029 Summer Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.2.1.4 Conclusions for No Loss of Load Allowed Simulations

If Edgewater unit #5 is retired as planned, there are several prior maintenance plus NERC Category P1 contingencies that result in unacceptably low voltages, indicating the potential for voltage instability.

Table 3.2.1
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Summer Peak Model, Edgewater Retired			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.1
P1	0	0	0	Appendix E, Table E.1
P2	0	0	0	Appendix E, Table E.1
P3	0	0	0	Appendix E, Table E.1

As shown in Table 3.2.2, twelve contingency combinations result in unacceptably low voltages and voltage instability. To verify potential voltage instability, initial TARA runs indicating low voltage will be verified by running the contingencies in PSS/E. Voltage instability is indicated when the PSS/E power flow model does not converge due to the inability to manage voltages.

Table 3.2.2
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Off-Peak Model, Edgewater Retired			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.2
P1	0	0	0	Appendix E, Table E.2
P2	0	0	0	Appendix E, Table E.2
P3	0	0	0	Appendix E, Table E.2
Prior Maint + P1	12	0	12	Appendix E, Table E.2

Table 3.2.3
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2029 Summer Peak Model, Edgewater Retired			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.3
P1	0	0	0	Appendix E, Table E.3
P2	0	0	0	Appendix E, Table E.3
P3	0	0	0	Appendix E, Table E.3

For comprehensive need documentation, refer to Appendix E.

3.2.2 NERC TPL Contingency Categories That Allow Loss of Load

NERC TPL-001-4 contingency categories that allow loss of load include the following for facilities 100 kV and above (unless otherwise noted):

- P2 – event resulting in the loss of a single element (HV bus section fault, HV non-bus tie breaker fault, bus tie breaker fault)
- P4 – for steady state power flow simulations, P4 HV defined contingencies are covered by P2s.
- P5 – for steady state power flow simulations, P5 HV defined contingencies are covered by P2s.
- P6 – P1 event followed by system adjustments, followed by Category P1 event
- P7 – any two adjacent circuits on a common structure

Voltage instability, cascading, or unplanned/uncontrolled load loss resulting from the above contingency definitions would generally drive the need to develop a solution option. Likewise, voltage and flows outside appropriate limits need to be addressed.

Planning to shed load pre-contingent is not an acceptable mitigation procedure. Appropriate automatic or manual load shed could be considered on a post-contingent basis. However, per MISO guidance, system voltages cannot be below 0.9 per unit unless there are automatic adjustments that can be made. For many of the contingencies described in this document, automatic adjustments are not available to raise voltages to appropriate limits.

The discussion described below does not cover all contingency limitations found within the study area, but only those that were determined to be reinforceable. Generally, there are circumstances under which the risk of a multiple contingency event to ATC and its customers may be sufficiently severe and may warrant reinforcement or other mitigation consideration:

- Generator instability for Category P2 non-EHV, P6 or P7, and
- When load at risk exceeds 100-300 MW, examine specific situations.

When ATC's analysis shows contingencies create impacts that reach these thresholds, ATC will consider not just trying to mitigate the impacts with planned and feasible load shedding but also with reinforcements. For further details regarding contingency types, please refer to Appendix A, Table A.1.

3.2.2.1 Edgewater Generation Retired Scenario, 2024 Summer Peak Model

A. CATEGORY P2 SIMULATIONS

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. CATEGORY P6 SIMULATIONS

For Category P6 contingencies within the study area, the following is a summary of the study results:

- Six contingencies combinations resulted in extremely low voltages (<0.80 per unit), indicating the potential for voltage instability. The worst outages are as follows:
 - Edgewater 345/138 kV T21 + Edgewater 345/138 kV T22
 - Edgewater-Cedarsauk 345 + Edgewater-South Fond du Lac 345
- The above two outages will solve in the PSS/E application with extremely low voltages but will not solve in the PowerWorld V20 application.
- Based on the contingencies analyzed for this category, the load at risk ranged from 180 MW to 230 MW.

C. CATEGORY P7 SIMULATIONS

For Category P7 contingencies within the study area, the following is a summary of the study results:

- One contingency resulted in extremely low voltages (~ 0.50 - 0.60 per unit), indicating the potential for voltage instability. It should be noted that a Category P7 contingency involves a single event. Once again, this outage does solve in the PSS/E application to show extremely low voltages, but does not solve in the PowerWorld V20 application.
 - The most load that ATC could serve would be 139 MW (blue line) to eliminate voltage instability for that given contingency. For 2500 hours of the year, potentially all the study area load is at risk, which equates to approximately 28% of the time. The amount of load at risk varies depending upon the amount of load online at the time of contingency and could be as much as the total study area peak load of 230 MW.
 - The most load that ATC could serve would be 135 MW (red line) to eliminate low voltages for this contingency. For 3100 hours of the year, potentially all the study area load is at risk, which equates to approximately 35% of the time. The amount of load at risk varies depending upon the amount of load online at the time of contingency and could be as much as the total study area peak load of 230 MW.

- Please refer to Section 3.5, Figure 3.5.1 for the voltage simulations indicating voltage instability and unacceptably low voltage points for this scenario.

The below load duration curve indicates MW values on the vertical axis and hours on the horizontal, for each of the three years 2017 through 2019. As shown, the load duration curves for each year are virtually identical.

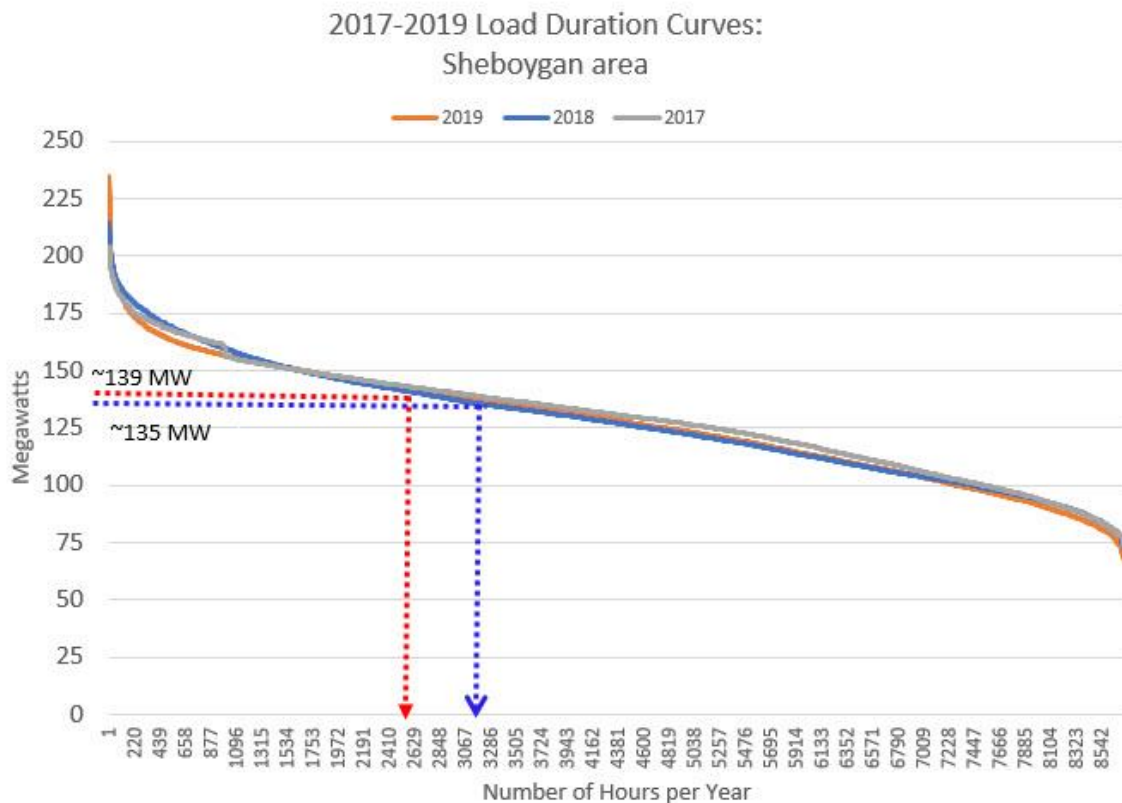


Figure 3.6: Planning Study Area, Load Duration Curves: Category P7 Event Outage

Extending the red-dashed line (~139 MW on the vertical axis) from any one of the curves on Figure 3.6 to the horizontal axis indicates that in order to avoid voltage instability for a single event, approximately 28% of the time, or 2500/8760 hours, all area load is at risk for voltage instability. Similarly, extending the blue-dashed line (~135 MW on the vertical axis) from any one of the curves to the horizontal axis indicates that in order to avoid low voltages for a single event, approximately 35% of the time, or 3100/8760 hours, all area load is at risk for low voltage conditions.

3.2.2.2 Edgewater Generation Retired Scenario, 2024 Off-Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

Category P6 results in the Off-Peak Model are identical to the prior maintenance plus single results described in Section 3.3.1.2(B).

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- One contingency resulted in extremely low voltages (~0.80 per unit), indicating voltage instability. It should be noted that a Category P7 contingency involves a single event.

3.2.2.3 Edgewater Generation Retired Scenario, 2029 Summer Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

For Category P6 contingencies within the study area, the following is a summary of the study results:

- Six contingency combinations resulted in extremely low voltages (<0.80 per unit), indicating the potential for voltage instability.
- Based on the contingencies analyzed for this category, the load at risk was 150-175 MW if the system reconfiguration outlined in Section 3.1.6 is used after the first outage. If the system reconfiguration outlined in Section 3.1.6 is not used, approximately 180-230 MW of load is at risk.

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies within the study area, the following is a summary of the study results:

- One contingency caused extremely low voltages (~0.50-0.60 per unit), resulting in voltage instability as shown in Figure 3.5.1. It should be noted that a Category P7 contingency involves a single event.

3.2.2.4 Conclusions for Loss of Load Allowed Simulations

As outlined above, several NERC contingencies that allow loss of load result in unacceptably low voltages, leading to voltage instability impacting approximately 180-230 MW of load within the Planning study area. Although loss of load is allowed to mitigate these contingencies, the results presented in Tables 3.2.4 through 3.2.6 indicate that there are a number of contingencies that result in the potential for voltage instability leading to potential loss of load.

This amount and duration of time that area load is at risk for these contingencies indicates the need to develop solution options.

Table 3.2.4
Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Summer Peak Model, Edgewater Retired			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.4
P6	6	0	6	Appendix E, Table E.4
P7	1	0	1	Appendix E, Table E.4

Table 3.2.5
Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Off-Peak Model, Edgewater Retired			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.5
P6	12	0	12	Appendix E, Table E.5
P7	0	0	0	Appendix E, Table E.5

Table 3.2.6
Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2029 Summer Peak Model, Edgewater Retired			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.6
P6	6	0	6	Appendix E, Table E.6
P7	1	0	1	Appendix E, Table E.6

Please refer to Appendix E for further details regarding contingency analysis.

3.2.3 NERC Extreme Events

NERC Planning Standards do not require reinforcement and ATC does not normally reinforce for these Extreme Event scenarios. As a result, these simulations were not performed as part of the Needs analyses. However, they were included in evaluating the performance of the alternatives to test their robustness. The results with and without each alternative are shown in Sections 4.1.4 and 4.2.4.

3.3 Sensitivity Analysis – Edgewater Generation Online

This sensitivity analysis utilized the same models as Section 3.2 with the following model revisions.

- Edgewater Power Plant – for all peak and off-peak models the generation remains online.

Please refer to Appendix A, Table A.1 for further details.

This section was not necessarily prepared in order to determine reinforceable contingencies, but rather to determine the potential impact upon the transmission system should the Edgewater Power Plant remain online.

3.3.1 NERC TPL Contingency Categories That Do Not Allow Loss of Load

Refer to Section 3.2.1 above for details regarding these types of contingencies.

3.3.1.1 Edgewater Online Scenario, 2024 Summer Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.3.1.2 Edgewater Online Scenario, 2024 Off-Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- Three prior maintenance plus Category P1 combinations resulted in extremely low voltages (<0.80 per unit), indicating the potential for voltage instability.

3.3.1.3 Edgewater Online Scenario, 2029 Summer Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.3.1.4 Conclusions for No Loss of Load Allowed Simulations

As outlined above, in the Edgewater Online modeling scenario there are no NERC “no load loss allowed” contingencies that result in system limitations.

Table 3.3.1
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Summer Peak Model, Edgewater Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.7
P1	0	0	0	Appendix E, Table E.7
P2	0	0	0	Appendix E, Table E.7
P3	0	0	0	Appendix E, Table E.7

Table 3.3.2
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Off-Peak Model, Edgewater Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.8
P1	0	0	0	Appendix E, Table E.8
P2	0	0	0	Appendix E, Table E.8
P3	0	0	0	Appendix E, Table E.8
Prior Maint + P1	3	0	3	Appendix E, Table E.8

Table 3.3.3
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2029 Summer Peak Model, Edgewater Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.9
P1	0	0	0	Appendix E, Table E.9
P2	0	0	0	Appendix E, Table E.9
P3	0	0	0	Appendix E, Table E.9

For comprehensive need documentation, refer to Appendix E.

3.3.2 NERC TPL Contingency Categories That Allow Loss of Load

Refer to Section 3.2.2 above for details regarding these types of contingencies.

3.3.2.1 Edgewater Online Scenario, 2024 Summer Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

For Category P6 contingencies within the study area, the following is a summary of the study results:

- Four contingency combinations resulted in extremely low voltages (~0.80 per unit or lower), indicating the potential for voltage instability.
- Based on the contingencies analyzed for this category, the load at risk ranged from 180 MW to 230 MW.

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.3.2.2 Edgewater Online Scenario, 2024 Off-Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

Category P6 results in the Off-Peak Model are identical to the prior maintenance plus single results described in Section 3.3.1.2(B).

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.3.2.3 Edgewater Online Scenario, 2029 Summer Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

For Category P6 contingencies within the study area, the following is a summary of the study results:

- Four contingency combinations resulted in extremely low voltages (~0.80 per unit or lower), indicating the potential for voltage instability.
- Based on the contingencies analyzed for this category, the load at risk ranged from 180 MW to 230 MW.

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.3.2.3 Conclusions for Loss of Load Allowed Simulations

As outlined above, several NERC contingencies that allow loss of load result in unacceptably low voltages, leading to the potential for voltage instability impacting between 150 and 200 MW of load at risk within the Planning study area. Although loss of load can be used to mitigate these contingency limitations, the results presented in Tables 3.3.4 through 3.3.6 indicate that there are a number of contingencies that result in a significant amount of load at risk. This amount of load at risk for these contingencies would indicate the need to develop solution options.

Table 3.3.4

Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Summer Peak Model, Edgewater Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.4
P6	4	0	4	Appendix E, Table E.4
P7	0	0	0	Appendix E, Table E.4

Table 3.3.5

Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Off-Peak Model, Edgewater Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.5
P6	3	0	3	Appendix E, Table E.5
P7	0	0	0	Appendix E, Table E.5

Table 3.3.6

Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2029 Summer Peak Model, Edgewater Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.6
P6	4	0	4	Appendix E, Table E.6
P7	0	0	0	Appendix E, Table E.6

These NERC Category P6 limitations can be mitigated by using the system reconfiguration outlined in Section 3.1.6. The usage of that procedure results in consequential loss of load should the second contingency occur, by radializing the system after the first outage occurs. This is acceptable from a NERC Compliance standpoint, but it is not optimal. This limits the loss of load to approximately 180 MW. If the second outage occurs without using the pre-contingent reconfiguration, there is the potential for 50 additional MW of load loss.

Please refer to Appendix E for further details regarding the contingency analysis.

3.4 Sensitivity Analysis – Other Proposed Area Generation Online

This sensitivity analysis utilized the same models as Section 3.2 (Edgewater generation assumed offline) with the following model revisions.

- J1153 Holland Solar (150 MW nameplate) was assumed online and dispatched using MISO methodology
 - 75 MW assumed online at summer peak
 - 75 MW assumed online during shoulder conditions
- J1171 Butternut Solar (100 MW nameplate) assumed online, dispatched using MISO methodology
 - 50 MW assumed online at summer peak
 - 50 MW assumed online during shoulder conditions

In addition, the Edgewater area load move discussed in Section 3.2 was removed (i.e. was modeled at the Edgewater 138 kV Substation instead of at a new site).

This section was not necessarily prepared in order to determine reinforceable contingencies, but rather to determine the potential impact upon the transmission system should the above generation proposals move forward in the MISO process.

3.4.1 NERC TPL Contingency Categories That Do Not Allow Loss of Load

Refer to Section 3.2.1 above for details regarding these types of contingencies.

3.4.1.1 Other Proposed Generation Online Scenario, 2024 Summer Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.4.1.2 Other Proposed Generation Online Scenario, 2024 Off-Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions, including prior maintenance plus single Category P1 outage within the study area, the following is a summary of the study results:

- No system overloads, and
- Six prior maintenance plus Category P1 combinations resulted in extremely low voltages (0.75-0.90 per unit), indicating the potential for voltage instability as shown in Figure 3.5.

3.4.1.3 Other Proposed Generation Online Scenario, 2029 Summer Peak Model

A. No Load Loss Allowed Simulations (P0 – P5)

Under normal and no load loss allowed contingency conditions within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.4.1.4 Conclusions for No Loss of Load Allowed Simulations

As outlined above, in the Other Proposed Generation Online modeling scenario there are no NERC “no load loss allowed” contingencies that result in system limitations.

Table 3.4.1
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Summer Peak, Edgewater Retired and Other Proposed Generation Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.7
P1	0	0	0	Appendix E, Table E.7
P2	0	0	0	Appendix E, Table E.7
P3	0	0	0	Appendix E, Table E.7

Table 3.4.2
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Off-Peak, Edgewater Retired plus Other Proposed Generation Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.8
P1	0	0	0	Appendix E, Table E.8
P2	0	0	0	Appendix E, Table E.8
P3	0	0	0	Appendix E, Table E.8
Prior Maint + P1	6	0	6	Appendix E, Table E.8

Table 3.4.3
Summary of Reinforceable No Load Loss Allowed Contingency Simulations

NERC Contingency	2029 Summer Peak, Edgewater Retired plus Other Proposed Generation Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P0	0	0	0	Appendix E, Table E.9
P1	0	0	0	Appendix E, Table E.9
P2	0	0	0	Appendix E, Table E.9
P3	0	0	0	Appendix E, Table E.9

For comprehensive need documentation, refer to Appendix E.

3.4.2 NERC TPL Contingency Categories That Allow Loss of Load

Refer to Section 3.2.2 above for details regarding these types of contingencies.

3.4.2.1 Other Proposed Generation Online Scenario, 2024 Summer Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

For Category P6 contingencies within the study area, the following is a summary of the study results:

- Five contingency combinations resulted in extremely low voltages (0.8 per unit or lower), indicating the potential for voltage instability.
- Based on the contingencies analyzed for this category, the load at risk ranged from 180 MW to 230 MW.

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies within the study area, the following is a summary of the study results:

- No system overloads, and
- One contingency resulted in extremely low voltages (~0.70 per unit), indicating voltage instability. It should be noted that a Category P7 contingency involves a single event. This contingency solves in the PSS/E application but does not solve in the PowerWorld application.

3.4.2.2 Other Proposed Generation Online Scenario, 2024 Off-Peak Model

A. [CATEGORY P2 SIMULATIONS](#)

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. [CATEGORY P6 SIMULATIONS](#)

Category P6 results in the Off-Peak Model are identical to the prior maintenance plus single results described in Section 3.4.1.2(B).

C. [CATEGORY P7 SIMULATIONS](#)

For Category P7 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

3.4.2.3 Other Proposed Generation Online Scenario, 2029 Summer Peak Model

A. CATEGORY P2 SIMULATIONS

For Category P2 contingencies where loss of load is allowed within the study area, the following is a summary of the study results:

- No system overloads, and
- No voltage limitations.

B. CATEGORY P6 SIMULATIONS

For Category P6 contingencies within the study area, the following is a summary of the study results:

- Five contingency combinations resulted in extremely low voltages (~0.80 per unit or lower), indicating the potential for voltage instability.
- Based on the contingencies analyzed for this category, the load at risk ranged from 180 MW to 230 MW.

C. CATEGORY P7 SIMULATIONS

For Category P7 contingencies within the study area, the following is a summary of the study results:

- No system overloads, and
- One contingency resulted in extremely low voltages (~0.70 per unit), indicating voltage instability. It should be noted that a Category P7 contingency involves a single event.

3.4.2.3 Conclusions for Loss of Load Allowed Simulations

As outlined above, several NERC contingencies that allow loss of load result in unacceptably low voltages, leading to the potential for voltage instability impacting between 180 and 230 MW of load at risk within the Planning study area. Although loss of load can be used to mitigate these contingency limitations, the results presented in Tables 3.4.4 through 3.4.6 indicate that there are a number of contingencies that result in a significant amount of load at risk. This amount of load at risk for these contingencies would indicate the need to develop solution options.

Table 3.4.4
Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Summer Peak, Edgewater Retired plus Other Proposed Generation Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.7
P6	5	0	5	Appendix E, Table E.7
P7	1	0	1	Appendix E, Table E.7

Table 3.4.5
Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2024 Off-Peak, Edgewater Retired plus Other Proposed Generation Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.8
P6	6	0	6	Appendix E, Table E.8
P7	0	0	0	Appendix E, Table E.8

Table 3.4.6
Summary of Reinforceable Load Loss Allowed Contingency Simulations

NERC Contingency	2029 Summer Peak, Edgewater Retired plus Other Proposed Generation Online			
	Voltage instability	Overloads	Low voltages	Appendix Table Reference
P2	0	0	0	Appendix E, Table E.9
P6	5	0	5	Appendix E, Table E.9
P7	1	0	1	Appendix E, Table E.9

These NERC Category P6 limitations can be mitigated by using the system reconfiguration outlined in Section 3.1.6. The usage of that procedure results in consequential loss of load should the second contingency occur, by radializing the system after the first outage occurs. This is acceptable from a NERC Compliance standpoint, but it is not optimal. This limits the loss of load to approximately 180 MW. If the second outage occurs without using reconfiguration, there could be potential for 50 additional MW of load lost.

Please refer to Appendix E for further details regarding the contingency analysis.

3.5 Voltage Instability Simulation Results

3.5.1 VSAT Simulations

The purpose of this section is to confirm that the voltage stability indicators that appear in Section 3.2 are indeed due to voltage instability and not due to software limits. The Needs analysis results presented for the Edgewater Retired scenario described contingencies that resulted in voltage instability (non-convergence of the power flow model). Actual simulations performed by the PSS®E simulation tool that result in non-convergence may not always represent voltage instability. In some instances, continual interactions between capacitor banks or other switched devices may cause the simulation to diverge from a final solution. In other models, non-convergence is indeed caused by voltage instability due to the severe nature of the contingency resulting in a weakened system to adequately maintain system voltages.

The VSAT (Voltage Security Assessment Tool) application, Version 19, by Power Tech Labs was used to validate the voltage instability scenarios in the planning study area. The tool simulates the specified critical contingencies at increasing power transfers or load levels, with bus voltages monitored at each step. Contingencies resulting in actual voltage instability can be identified by the shape of the P-V (power vs. voltage) curves that show a continuing degradation of voltage.

To illustrate the potential for voltage instability related to two of the most severe contingencies identified earlier in the Section 3, ATC performed VSAT studies on the 2024 Summer Peak, Edgewater Retired scenario, with the examples and results described below and outlined more fully in Appendix L. The study models were modified by reducing the study area load to approximately 40% of peak, then continually increasing the load (replaced with power from ATC Planning Zones 3 and 5 generation) to represent increasing imports into the study area.

The two contingencies used the 2024 Summer Peak Edgewater Retired scenario without mitigation for the VSAT simulations. The contingencies of interest are as follows:

- [REDACTED]
- [REDACTED]

For these contingencies, several buses scattered throughout the study area were monitored, depending upon the contingency being studied:

- Huebner 138,
- Erdman 138,
- Kohler 138,
- Lodestar 138, and
- Northgate 138.

Figures 3.5.1 and 3.5.2 show that the area starts to become unstable for these contingencies when the load level approaches ~130-140 MW. Since the area peaks have been in the -210-230 MW range (as

shown in the load duration curves listed in Section 3.2), this clearly indicates that the area is at risk for voltage instability should these contingencies occur.

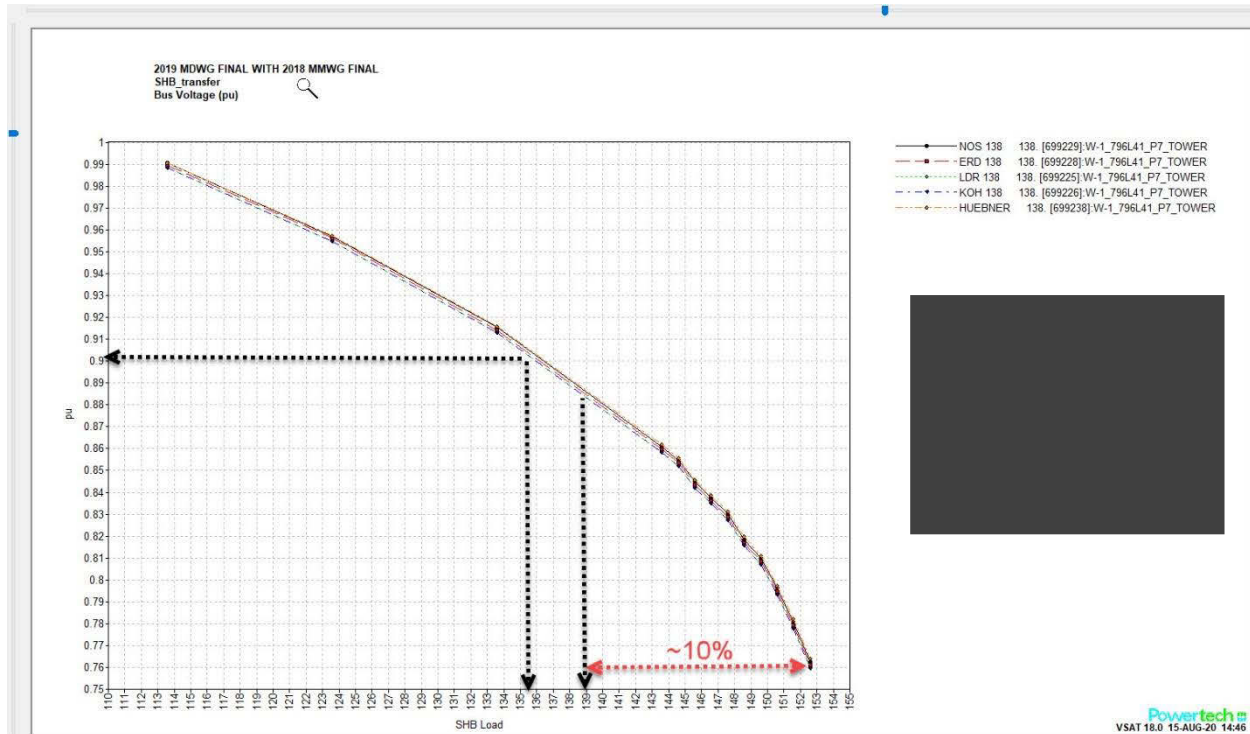


Figure 3.5.1: VSAT Results for [REDACTED]

Per ATC Planning Criteria, approximately 10% from the “nose” of the curve indicates voltage instability, as shown in Figure 3.5.1.¹

¹ A way to calculate the 10% is to look at how rapidly the points are changing. An indicator of the instability point is where many solution points start grouping together as shown to the right of the curve. The 10% point is chosen halfway between the start of that group of points and the last solution point, which in Figure 3.5.1 equates to ~139 MW.

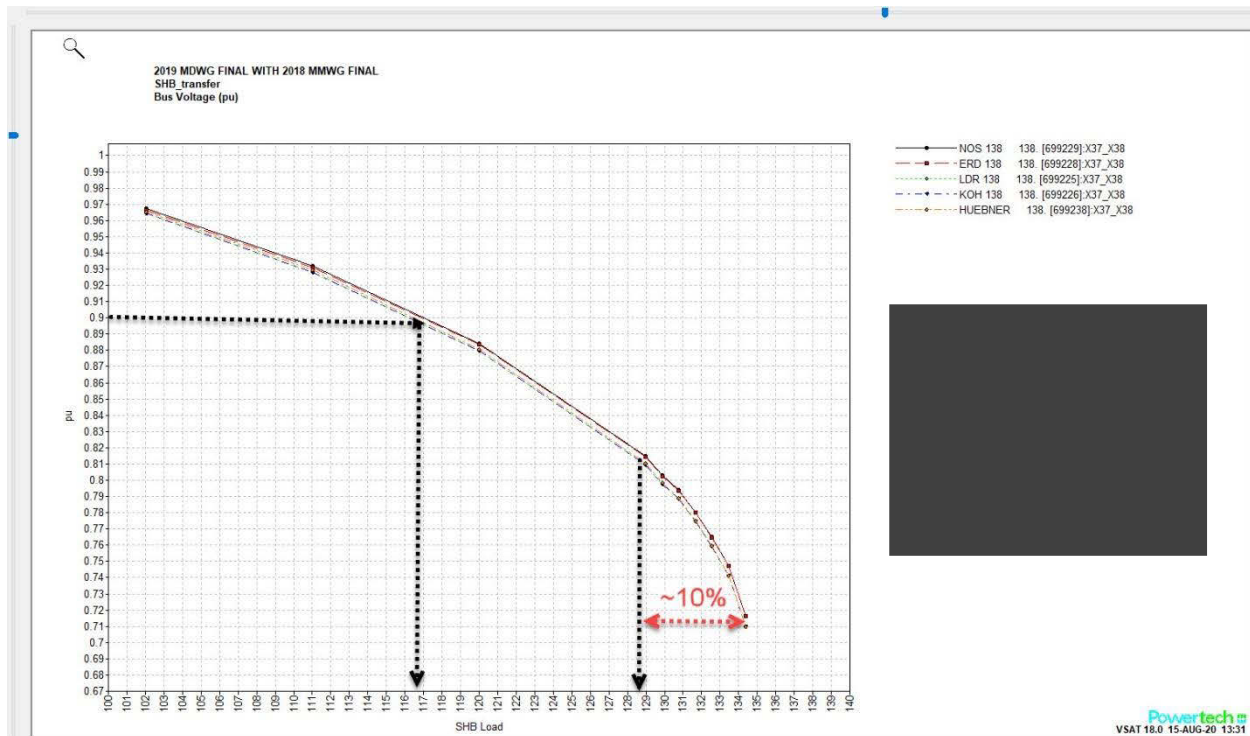


Figure 3.5.2: VSAT Results for [REDACTED] outages: Voltage instability at ~129 MW, Low voltages at ~ 117 MW

VSAT analysis indicates that voltage instability will occur for each of these scenarios at the load levels shown. It should also be noted that unacceptably low voltages (<0.9 per unit) are observed at much lower levels than voltage instability, indicating the need for reinforcement prior to voltage instability.

This analysis illustrates that the planning study area is indeed vulnerable to voltage instability. As the planning study area load increases, critical contingencies can lead to potential voltage degradation and significant load loss. It should be noted that the VSAT studies are steady-state analyses, and do not consider possible dynamic performance characteristics. These could include tripping of motor loads, or possible increased load currents on other types of loads at lower voltages. The VSAT studies however do provide an accurate indicator that imminent voltage instability or extremely low voltages can occur.

3.6 Summary of Need Drivers

The planning study area possesses unique characteristics contributing to the need for increased transmission facilities due to the large [REDACTED] load that is generally on 24 hours a day, seven days a week. Additionally, there are only two 345 kV circuits and one 138 kV circuit feeding the area. For approximately seven miles, these two 345 kV circuits share towers, resulting in the potential of a single point of failure for both 345 kV lines.

ATC performed analysis on the 2024 and 2029 Summer Peak and 2024 Off-Peak modeling scenarios for NERC Categories that do not allow loss of load. ATC found no limitations for these types of contingencies.

ATC performed analysis on the 2024 and 2029 Summer Peak and 2024 Off-Peak modeling scenarios for NERC Categories that do allow loss of load. ATC found that some contingencies result in extremely low voltages, indicating the potential for voltage instability.

For NERC Categories that allow loss of load, the following are the most severe contingencies leading to voltage instability:

- Category P6: Edgewater-Lodestar 138 plus 20th Street-Erdman 138
- Category P6: Edgewater-Lodestar 138 plus Edgewater-Edgewater Distribution 138
- Category P6: Edgewater 345/138 T21 plus Edgewater 345/138 T22
- Category P7: Edgewater-South Fond du Lac 345 plus Edgewater-Cedarsauk 345 tower

ATC could consider shedding load for some limitations from these contingencies, but NERC Reliability Standards do not allow system instability such as voltage instability without reinforcing the system.

in the Off-Peak modeling scenario, several prior maintenance plus NERC Category P1 contingencies indicate unacceptably low voltages and the potential for voltage instability. The following are the most significant contingencies:

- Prior Maintenance + Category P1: 20th Street-Sauk Trails 138 (X-37) plus outage of Edgewater-Lodestar 138 (X-38)
- Prior Maintenance + Category P1: Edgewater-Sauk Trails 138 (X-37) plus outage of Edgewater-Lodestar 138 (X-38)
- Prior Maintenance + Category P1: Edgewater-Huebner 138 (X-38) plus outage of Edgewater-Edgewater Distribution 138 (X-153)
- Prior Maintenance + Category P1: Edgewater-Huebner 138 (X-38) plus outage of Edgewater-20th Street 138 (X-37)
- Prior Maintenance + Category P1: Edgewater-Huebner 138 (X-38) plus outage of 20th Street-Erdman 138 (X-64)
- Prior Maintenance of Lodestar-Huebner 138 (X-38) plus outage of Edgewater-20th Street 138 (X-37)

ATC performed sensitivity analysis to determine system impacts if the Edgewater generation remains online. The analysis of the sensitivity (Section 3.3) indicates that even when the unit remains online and operational, category P6 (and associated prior maintenance plus NERC Category P1) contingency limitations remain.

Similarly, ATC performed sensitivity analysis to determine impacts if the proposed generation additions at Butternut and Holland move forward and Edgewater 5 retires. The analysis of that sensitivity found in Section 3.4 indicates that even with some replacement generation in the area, NERC Category P6, P7, and prior maintenance plus Category P1 limitations remain. Although some of the Edgewater generation being retired could be replaced, the chosen generation sites do nothing to improve the area limitations, mainly because the contingencies themselves isolate the rest of the system from the proposed new generation.

As discussed in Section 3.5, the analysis confirms that the study area is vulnerable to voltage instability. As the planning study area load increases, critical contingencies can lead to potential voltage degradation and loss of load of up to 230 MW. Voltage instability and instability suggested by extremely low voltages found in power flow simulations are verified by the VSAT simulations for certain contingencies.

Due to the Edgewater unit retirement, planning study area load, generation and transmission capacity are even further out of balance. This imbalance drives the additional reliability need for system reinforcements within the planning study area. This means that the risk of voltage instability and the amount of load that would be lost for outages is increasing. Even with the Edgewater unit online, the area is susceptible to unacceptably low voltages. With the Edgewater unit retired, the risk for load loss is even more unacceptable.

4. System Alternatives

This section presents system alternatives, including the proposed project, that address the identified needs as shown in Section 3. Route alternatives should not be confused with system alternatives. Route alternatives differ from system alternatives because routes are different paths considered to get a line between the same two end points. No route alternatives are discussed in this document. The geographical diagrams representing the alternatives in this section are not necessarily indicative of routes.

Several reinforcement options were considered to address the reliability needs within the planning study area. Of these, only the best performing reinforcements will be discussed in this section as alternatives. The other reinforcement options that were evaluated but not considered as viable system alternatives are outlined in Section 4.3.

The robustness of the alternatives discussed in this section was evaluated as follows:

- NERC Category E2.C contingencies (loss of a substation, one voltage level plus transformer), and
- Prior maintenance of an element followed by a tower (Category P7) contingency

In order to create the models used in the Alternatives Analysis, power flow models utilized in Section 3.2 were used as a starting point.

The power flow results below assume that each alternative is implemented and in service. Comprehensive alternative comparison tables can be found in Appendix E.

4.1 Alternative #1: Howards Grove-Erdman 138 kV Circuit

The scope of this alternative includes the following transmission facilities and is further defined in the Project Diagram shown in Appendix D.

- New Howards Grove - Erdman 138 kV line,
- Expansion of the existing Erdman 138 kV Substation, and

- Expansion of Howards Grove 138 kV straight bus into a 4-position ring bus.

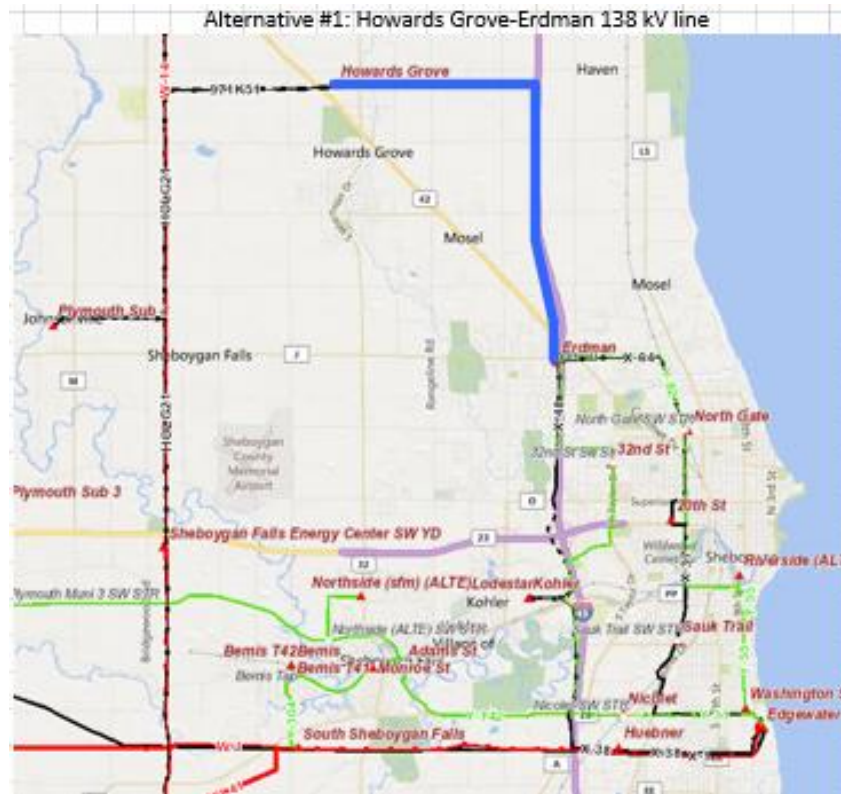


Figure 4.1.1
Geographical Scope of Alternative 1

The following sub-sections will highlight the performance of this alternative. Power flow results are summarized in Appendix E.

4.1.1 2024 Summer Peak Modeling Scenario

Tables E1 through E9 in Appendix E list all contingencies and limitations in the study area. Alternative #1 successfully addresses all of the contingency limitations.

4.1.2 2024 Off-Peak Modeling Scenario

Tables E1 through E9 in Appendix E list the contingencies and limitations in the study area. Alternative #1 successfully addresses all contingency limitations.

4.1.3 2029 Summer Peak Modeling Scenario

Tables E1 through E9 in Appendix E list the contingencies and limitations in the study area. Alternative #1 successfully addresses all contingency limitations.

4.1.4 Robustness Tests

4.1.4.1 2024 Summer Peak Model, Category E2.C Analysis

An additional sensitivity study was performed to identify the performance of Alternative #1 for specific NERC Category E2.C contingencies. Category E2.C contingencies are defined as the simultaneous loss of a switching station or substation (Extreme Event, outage of substation at one voltage level plus transformers). Substations studied as part of this analysis were:

- Edgewater 345
- Edgewater 138
- Cedarsauk 345
- Sheboygan Energy Center 345
- Saukville 138
- Erdman 138

Each simulation was performed on the 2024 Summer Peak model, with intact system conditions (no prior outage). The results are shown in Appendix E, Table E.1. There is one contingency that results in voltage limitations with no alternatives applied to the case. After Alternative #1 was applied there are zero E2.C contingencies that result in limitations. NERC requires ATC to know the risks and consequences of these contingencies but does not require reinforcement. ATC does not normally reinforce for these scenarios.

4.1.4.2 2024 Off-Peak Modeling Scenario, Prior Outage Plus Tower Contingencies

An additional sensitivity study was performed to identify the performance of Alternative #1 for specific prior maintenance plus NERC Category P7 contingencies. Category P7 contingencies are defined as the loss of any two adjacent circuits on a common tower. Category P7 studied as part of this analysis was:

- [REDACTED]

The simulation was performed on the 2024 Off-Peak model, with the tower contingency assumed. NERC Category P1 contingencies were run assuming the Category P7 outage has already occurred. The results are shown in Appendix E, Table E.1. There were no prior maintenance plus Category P7 contingencies that resulted in thermal or voltage limitations with alternatives applied.

After Alternative #1 was applied there are zero contingencies that result in limitations. NERC requires ATC to know the risks and consequences of these contingencies but does not require reinforcement. ATC does not normally reinforce for these scenarios.

4.1.5 Voltage Stability Analyses

Voltage stability analysis was performed as described in Section 3.5 with this Alternative Assumed in service.

4.1.5.1 VSAT Simulations

For all contingencies studied and discussed in Section 3.5 with Alternative #1 assumed in service, the potential for low voltages and voltage instability was eliminated.

4.1.6 Loss Analyses

System MW loss studies on the 2024 Summer Peak and Off-Peak Modeling Scenarios were performed with the results shown in Appendix G. The results show a system loss reduction of 0.3 MW for the summer peak model and 0.1 MW for the off-peak model with Alternative #1.

4.1.7 Project Cost

The Planning level estimate for Alternative #1 is \$21.6 million in 2023 dollars. This estimate can be broken down into the following categories.

- Howards Grove substation expansion: \$2.2 million
- Erdman substation expansion: \$4.7 million
- New Howards Grove – Erdman 138 kV T-Line: \$13.6 million
- Pre-certification: \$1.1 million

4.1.8 Summary of Alternative #1

In the summer peak and off-peak modeling scenarios, the performance of System Alternative #1 met ATC's Planning Criteria. It addressed all Category P0 through P7 contingencies in the study area.

Tables E.1 through E.10 in Appendix E show the results for area once Alternative #1 is in service. With this alternative assumed in-service, all the limitations identified in the summer peak and off-peak modeling scenarios are addressed.

When Alternative #1 is tested for robustness and future flexibility, the following key conditions were observed:

- All studied extreme event (Category E2.C) contingency limitations were mitigated.

This alternative will improve system efficiency by reducing system losses by 0.3 MW in the 2024 Summer Peak modeling scenario and 0.1 MW in the off-peak modeling scenario.

One of the benefits of Alternative #1 is that it is the lowest cost solution to address identified needs. Alternative #1 also provides for robustness because it addresses NERC Extreme Event (E2.C, Loss of a substation, one voltage level plus transformers) contingency limitations.

4.2 Alternative #2: Plymouth-Erdman 138 kV Circuit

The scope of this alternative includes the following transmission facilities and is further defined in the Project Diagram shown in Appendix D.

- New Plymouth - Erdman 138 kV line,

- New 138 kV bus tie breaker at Erdman, and
- Expansion of Plymouth #4 bus.

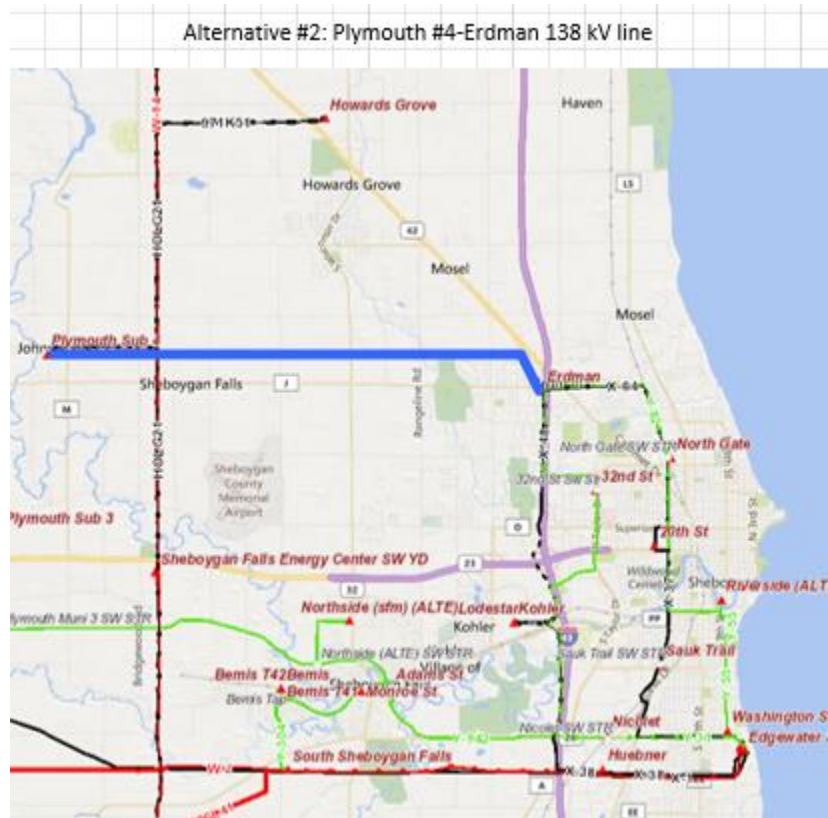


Figure 4.2.1
Geographical Scope of Alternative 2

The following sub-sections will highlight the performance of this alternative. Power flow results are summarized in Appendix E.

4.2.1 2024 Summer Peak Modeling Scenario

Tables E1 through E9 in Appendix E list all contingencies and limitations in the study area. Alternative #2 successfully addresses all contingency limitations.

4.2.2 2024 Off-Peak Modeling Scenario

Tables E1 through E9 in Appendix E list the contingencies and limitations in the study area. Alternative #2 successfully addresses all contingency limitations.

4.2.3 2029 Summer Peak Modeling Scenario

Tables E1 through E9 in Appendix E list the contingencies and limitations in the study area. Alternative #2 successfully addresses all contingency limitations.

4.2.4 Robustness Tests

4.2.4.1 2024 Summer Peak Modeling Scenario, Category E2.C Analysis

An additional sensitivity study was performed to identify the performance of Alternative #2 for specific Category E2.C contingencies. Category E2.C contingencies are defined as the simultaneous loss of a switching station or substation (one voltage level plus transformers). Substations studied as part of this analysis were described in Section 4.1.4.1.

Each simulation was performed on the 2024 Summer Peak model, with intact system conditions (no prior outage). The results are shown in Appendix E, Table E.1. There is one contingency that results in voltage limitations with no alternatives applied to the case. After Alternative #2 was applied there are zero E2.C contingencies that result in limitations. NERC requires ATC to know the risks and consequences of these contingencies but does not require reinforcement. ATC does not normally reinforce for these scenarios.

4.2.4.2 2024 Off-Peak Modeling Scenario, Prior Outage Plus Tower Contingencies

An additional sensitivity study was performed to identify the performance of Alternative #2 for specific prior maintenance plus NERC Category P7 contingencies. Category P7 contingencies are defined as the loss of any two adjacent circuits on a common tower. Category P7 studied as part of this analysis was:

- [REDACTED]

The simulation was performed on the 2024 Off-Peak model, with the tower contingency assumed. NERC Category P1 contingencies were run assuming the Category P7 outage has already occurred. The results are shown in Appendix E, Table E.1. There were no prior maintenance plus Category P7 contingencies that resulted in thermal or voltage limitations with alternatives applied.

After Alternative #2 was applied there are zero contingencies that result in limitations. NERC requires ATC to know the risks and consequences of these contingencies but does not require reinforcement. ATC does not normally reinforce for these scenarios.

4.2.5 Voltage Stability Analyses

Voltage stability analysis was performed as described in Section 3.5 with this Alternative Assumed in service.

4.2.5.1 VSAT Simulations

For all contingencies studied with Alternative #2 assumed in service, the potential for low voltages and voltage instability was eliminated.

4.2.6 Loss Analyses

System MW loss studies on the 2024 Summer Peak and Off-Peak Modeling Scenarios were performed with the results shown in Appendix G. The results show a system loss reduction of 0.2 MW for the summer peak model and 0.1 MW for the off-peak model with Alternative #2 in service.

4.2.7 Project Cost

The Planning level estimate for Alternative #2 is \$26.4 million in 2026 dollars. This estimate can be broken down into the following categories.

- Plymouth substation modifications: \$3.3 million
- Erdman substation modifications: \$2.2 million
- New Plymouth – Erdman 138 kV T-Line: 19.7 million
- Pre-certification: \$1.2 million

4.2.8 Summary of Alternative #2

In the summer peak and off-peak modeling scenarios, the performance of System Alternative #2 met ATC's Planning Criteria. It addressed all Category P0 through P7 and prior maintenance plus Category P7 contingencies in the study area.

Tables E1 through E9 in Appendix E show the needs for area once Alternative #2 is in service. With this alternative assumed in-service, all the limitations identified in the summer peak and off-peak modeling scenarios are addressed.

When Alternative #2 is tested for robustness and future flexibility, the following key conditions were observed:

- All extreme event contingency limitations were mitigated.

This alternative will improve system efficiency by reducing system losses by 0.2 MW in the 2024 Summer Peak modeling scenario and 0.1 MW in the off-peak model.

Alternative #2 also provides for robustness because it addresses NERC Extreme Event (E2.C, Loss of a substation, one voltage level plus transformers) contingency limitations.

4.3 List of Other Transmission Options Not Pursued

There were several options that were considered, studied and not pursued for various reasons.

4.3.1 Maintain Existing System, Edgewater Retired

This maintain existing system option once Edgewater is retired will not resolve the contingency limitations described in Section 3. The list of limitations described in that section represents a significant risk to system reliability throughout the study area.

Due to the high level of risk to system reliability, maintaining the existing system is not a viable option; and contrary to NERC requirements and ATC's statutory obligation to provide a reliable electric transmission system for the areas it serves.

4.3.2 Energy Storage

This option would require an appropriately sized energy storage device in the area that would be able to react fast enough to solve the voltage limitations seen in Section 3. To address all NERC Category P6 and

P7 limitations outlined in Section 3, one 100 MW, 4-hour duration battery is needed at Edgewater, and one 100 MW, 4-hour duration battery is needed at Erdman. Please see summary Table 4.5.2 below:

Table 4.5.2: Amount of Energy Storage Needed to Address Area NERC Limitations

Locations	Size in MVAR	High-Level Cost Estimate
Edgewater 138 kV	100 MW, 4-hour duration	\$114M
Erdman 138 kV	100 MW, 4-hour duration	\$114M
Totals		\$228M

As shown, the cost of reactive support to address NERC contingency limitations is almost ten times the cost of the preferred project outlined in this document. Due to the cost of an energy storage solution, this option was not pursued.

4.3.3 Reactive Compensation

When considering solutions in Wisconsin, many contingencies resulted in the potential for voltage instability, so a reactive compensation (SVC or STATCOM) solution was studied to help support the voltage during these contingencies. To address all NERC Category P6 and P7 limitations outlined in Section 3, one 150 MVAR unit at Edgewater and one 100 MVAR unit at Erdman are needed. The correctly sized reactive compensation to address all NERC Category P6 and P7 limitations is listed in Table 4.3.3:

Table 4.3.3: Reactive Compensation Needed to Address Area NERC Limitations

Locations	Size in MVAR	High-Level Cost Estimate
Edgewater 138 kV	150 MVAR	\$21M
Erdman 138 kV	100 MVAR	\$19M
Totals	250 MVAR	\$40M

As shown, the cost of reactive support to address NERC contingency limitations is approximately twice as much as the cost of the preferred project outlined in this document. Due to the cost of a reactive compensation solution, this option was not pursued.

4.3.4 New Mullet River-Holland area, 138 kV ring bus

An option to tie existing 138 kV lines Mullet River-South Sheboygan Falls (X-57) and Holland-Howards Grove (HOLG21) together to create a 4-position ring bus was studied. Although this option provides for some improvement under certain contingencies, it did not address all limitations outlined in Section 3, such as the NERC Category P6 (peak or off-peak) outage of Edgewater-Lodestar 138 kV line plus the outage of the 20th Street-Erdman 138 kV line. As a result, this solution option was not pursued.

4.3.5 Construct Double-Circuit Line from Howards Grove to Erdman, tie into line X-64 (20th Street – Erdman 138 kV)

An option to construct a double-circuit line from Howards Grove to Erdman, tying into existing line X-64 (instead of terminating a new line at Erdman) was studied. Although this option provides for some improvement under certain contingencies, it did not address all limitations outlined in Section 3, such as the NERC Category P6 (peak or off-peak) outage of Edgewater-Lodestar 138 kV line plus the outage of the 20th Street-Erdman 138 kV line. As a result, this solution option was not pursued.

4.3.6 Construct Double-Circuit Line from Howards Grove to Erdman, tie into line X-48 (Erdman – Lodestar 138 kV)

An option to construct a double-circuit line from Howards Grove to Erdman, tying into existing line X-48 (instead of terminating a new line at Erdman) was studied. Although this option provides for some improvement under certain contingencies, it did not address all limitations outlined in Section 3, such as the NERC Category P6 (peak or off-peak) outage of Edgewater-Lodestar 138 kV line plus the outage of the 20th Street-Erdman 138 kV line. As a result, this solution option was not pursued.

5. System Alternative Comparison

This purpose of this section is to present and compare the performance of the alternatives outlined in Section 4 using various criteria. The alternatives are compared from a reliability standpoint (including future robustness), voltage performance, and costs.

5.1 Alternative Comparison

5.1.1 Reliability Comparison

This section compares power flow results, system losses, and estimated cost for each of the four alternatives described in Section 4.

To compare power flow performance, two results were considered. Results from contingencies and scenarios that would require reinforcement, and results from scenarios beyond those conditions. Scenarios beyond those conditions indicate how robust the alternative is, but the results of these scenarios would not necessarily justify the need for the project.

Table 5.1.1 compares the study results from the modeling scenario studied. Alternatives 1 and 2 resolve all contingency limitations within the study area.

Table 5.1.1
Summary of Remaining Contingencies with Limitations Summary

Modeling Scenario	Alternative #1	Alternative #2
2024 Summer Peak and Off-Peak	0	0
2029 Summer Peak	0	0
Totals	0	0

Additional simulations were performed to test the robustness of the alternatives. The intent of these simulations is an additional comparison tool to identify the robustness of the alternatives and to see how they might perform when various uncertainties are included in the models. ATC examined the prior maintenance plus NERC Category P7 condition as well as the NERC Extreme Event (Category E2.C) scenarios. Both alternatives resolve all contingency limitations within the study area as shown in Table 5.1.2.

Table 5.1.2
Remaining Contingencies with Limitations Summary
Robustness Performance Tests

Modeling Scenario	Alternative #1	Alternative #2
Prior Maintenance plus Category P7	0	0
NERC Category E2.C Extreme Event	0	0
Totals	0	0

Table 5.3 is a comparison of the planning level cost estimate and system losses. Both alternatives perform similarly from a loss perspective.

Table 5.1.3
Alternative Comparison Summary
Project Costs and System Losses

Comparison Factor	Alternative #1	Alternative #2
Project Planning Level Cost Estimate (2026 dollars)	\$23.4	\$28.9
Δ ATC losses (MW)	-0.3	-0.3
Δ System losses (MW)	-0.3	-0.2
Δ ATC losses (MW)	-0.1	-0.1
Δ System losses (MW)	0.0	0.0

5.1.2 Voltage Performance Alternative Comparison Results

All alternatives resolve the voltage stability issues outlined in Section 3.5.

5.1.3 Summary of Alternative Comparison

Two alternatives were evaluated to address the study area limitations. Both alternatives involve constructing new transmission lines with new right-of-way.

When looking at reliability, Alternative #1 and #2 perform identically when compared to one another in every category. However, Alternative #2 is the more expensive alternative.

As outlined in Sections 5.1.1 and 5.1.2, when reliability, voltage performance and cost are considered, Alternative #1 is the best alternative to address study area needs.

6. Economic Benefits Summary

The Howards Grove-Erdman area project was primarily developed to address reliability concerns related to the Edgewater unit #5 retirement. An economic benefits screening analysis was completed, and it was determined that the project did not provide significant benefits and did not result in any reduction in economic benefits.

7. PSC Authorization Requirements

The preferred alternative includes a new 138 kV line on new right-of-way in the state of Wisconsin. It has been determined that ATC will need to file a CPCN application with the PSCW.

8. Other Considerations

8.1 Delayability

To maintain system reliability, the proposed project identified in this report should be completed prior to the retirement of the Edgewater generation. At this time, Edgewater unit #5 is planned for retirement in the year 2022. ATC is currently working with MISO to develop an Operating Guide to utilize in the interim period between the time the generator retires, and the new line can be built.

8.2 Coordination with Future Plans

The proposed project is consistent with ATC's transmission plans.

The proposed project is consistent with plans that were developed through the MISO MTEP20 planning process.

This project was most recently screened as part of ATC's 2020 10-Year Assessment and is consistent with the projects identified in the assessment.

8.3 Non-Transmission Options

8.3.1 Introduction

The following sections outline energy efficiency assessment and generation options.

8.3.2 Energy Efficiency Assessment Impact

This section considers whether demand reduction in the Howards Grove-Erdman study area could eliminate the need for or reduce the scope of this project.

- This project is primarily driven by the retirement of the Edgewater unit #5 generation described in Section 3.

- As outlined in Section 3.5, the potential for voltage instability occurs during peak and off-peak conditions for several contingencies. Removing potential for voltage instability would require reduction of approximately 70-90 MW of load in a pocket of 210-230 MW of load.
- As outlined in Section 3.5, the potential for low voltages occurs during peak and off-peak conditions for several contingencies. Removing potential for low voltage would require reduction of approximately 120 MW of load in a pocket of 210-230 MW of load.
- Discussions with Alliant Energy indicate that there are no energy efficiency programs available to reduce area load by this magnitude.

To address area needs outlined in Section 3 and to provide flexibility to address the impact of the Edgewater unit retirement, it is unlikely there is an energy efficiency program that will provide similar benefits to the Howards Grove – Erdman area project.

8.3.3 Generation Alternatives

During the process of developing the Howards Grove-Erdman project, ATC monitored the MISO Generation Interconnection Queue to evaluate whether there were any generation alternatives close to the planning study area which might impact the need for the project. At the time of this analysis, there were no generation projects in the MISO Generation Interconnection Queue that would have an impact upon the scope of the proposed reinforcement project. There were two proposals (Holland and Butternut) that were tested as a sensitivity (Refer to Section 3.4). These potential generation additions had no impact upon the study area as outlined in that Section.

Notwithstanding the absence of generation options to resolve the needs in the planning study area, ATC performed a screening analysis on the 2024 modeling scenarios to determine the approximate size and installation cost of hypothetical generation options in the planning study area that might provide comparable reliability benefits. In the screening study, a minimum of approximately 150 MW of new completely dispatchable generation, with reliability matching traditional coal or gas fueled units (75 MW units at two sites) located within the 138/69 kV Sheboygan area loop were required to provide comparable reliability benefits to the proposed project. Specifically, the value of the generation is site-specific: Edgewater and Erdman 138 kV sites were studied. It should be noted that placing one 150 MW unit at either site does not address all area limitations.

Using MISO MTEP 19 cost assumptions for 2-75 MW Combustion Turbines in 2023, the total installed cost of \$148 million exceeds the cost of the proposed Howards Grove-Erdman project. This analysis does not attempt to value additional gas pipeline installation cost or the annual fuel and maintenance costs which would substantially increase the total generation alternative cost. Further details regarding this screening analysis are set forth in Appendix H.

The MISO also provides stakeholder vetted installed costs for combustible and non-combustible renewable generation alternatives. Biomass, onshore wind, hydro and photovoltaic generation options were approximately 11-29 times more expensive to install. The installation costs for these hypothetical options are also more costly than the proposed transmission project. In addition, the variable nature of the energy output from these intermittent resources makes evaluation of their ability to resolve the

reliability needs in the planning study area difficult to assess. MISO also provides installed costs for combustible renewable generation resources. Biomass facilities were approximately four times more expensive to install, respectively, than natural-gas facilities.

There are no technically feasible, cost-effective generation alternatives in the planning study area that would address the reliability needs and provide the benefits outlined in this Planning Analysis.

8.4 Coordination with Other Entities

ATC's coordination with external stakeholders includes the MISO MTEP review process.

ATC coordinated and cooperated with MISO on its assessment of this project to integrate transmission facilities into the BES. ATC notified MISO of the project and shared any information that MISO requested about its project assessment. The listing of the package of projects in Appendix A is confirmation that MISO has performed its own independent assessment of the package of projects.

8.5 Nuclear Plant Interface Coordination Requirements (NUC-001)

The Point Beach nuclear power plant is outside the planning study area of this project.

8.6 Target Ratings

ATC completed a NERC multiple outage screening review of the planning study area. In this analysis, ATC identified the target ratings for the proposed new Howards Grove –Erdman 138 kV line.

As a result of future uncertainties in combination with the long-life expectancy of a transmission line and the attempt to limit repeated landowner impacts, ATC went beyond the typical NERC Planning standards when identifying targeted ratings for the proposed facilities identified in this study.

For all severe system conditions studied, the 2029 summer peak scenario was used.

8.6.1 Howards Grove-Erdman 138 kV line

ATC obtained a loading of 1400 amps on the proposed Howards Grove – Erdman 138 kV circuit by performing the steps listed below. This was performed using the modeled conductor of T2-477 ACSR. The maximum normal rating for this conductor is 1229 amps and is associated with 200F conductor clearances.

To reach target rating, perform the following steps sequentially:

- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

For this circuit, ATC is proposing a normal target rating of 1200 amps for all seasons and a minimum 2-hour emergency rating of 1400 amps for all seasons. There is a margin applied in setting the targeted

emergency rating because of the long-life expectancy of a transmission line. The normal target rating of 1200 amps is flexible and could be adjusted to optimize the conductor-structure system design.

See the Project Diagram in Appendix D for details about ratings requirements.

8.7 Fault Duty Analysis

Fault duty analysis was done to ensure reasonable fault currents in the area with the preferred project in-service. The analysis is determined that there were no significant impacts.

8.8 Dynamic Stability Analysis

Dynamic stability analysis is not needed, as VSAT analysis outlined in Section 3.5 already identified the potential for voltage instability.

9. Conclusions

Based on the analysis and investigations performed for this report, ATC concludes that:

1. The Sheboygan, Wisconsin area possesses unique characteristics contributing to the need for increased transmission facilities. Limitations are significantly worsened if the Edgewater Power Plant retires as planned.
2. The load shape in the study area experiences a higher load factor than the remainder of the ATC System. This makes it extremely difficult to find times of the year to schedule transmission system maintenance.
3. The study area experiences voltages outside appropriate limits resulting from various contingencies as outlined in Section 3:
 - a. [REDACTED]
 - b. [REDACTED]
 - c. [REDACTED]
 - d. [REDACTED]

Each outage causes potential voltage instability or unacceptably low voltages under numerous

[REDACTED]
[REDACTED]
[REDACTED]

4. As a result of the Edgewater retirement, the risk of voltage instability and the amount of load that would be lost for multiple outages worsens. The risk for load loss is not acceptable.
5. Of the alternatives considered to address the transmission system needs in the planning study area, Alternative #1 provides the best solution when performance, costs and robustness are considered.
6. A benefit of all alternatives is that they resolve certain NERC Extreme Event contingency limitations.
7. A benefit of all alternatives is that they reduce system losses.

8. ATC has determined that even if Edgewater remains online, there are system limitations that need to be addressed.
9. Due to the urgent and increasing need for reinforcements, the proposed project identified in this report should be completed prior to the retirement of the generation at the Edgewater Power Plant.
10. ATC has determined an achievable in-service date is approximately late 2023, or as soon as practical.

11. Revisions

- a. 4-26-21: updated cost estimates to reflect adjusted scope.

Appendices

- Appendix A: Methodology, Assumptions and Criteria
- Appendix B: Study Area
- Appendix C: Existing System
- Appendix D: Project Diagram
- Appendix E: Needs and Alternatives Analysis
- Appendix F: MW Load Forecast
- Appendix G: Megawatt Loss Analysis
- Appendix H: Generation Alternatives

Appendix A. Methodology, Assumptions and Criteria

A.1 Methodology

The majority of the steady state AC power flow simulations conducted for the Project Need and Alternatives analysis were performed using the Power Flow module of the Power System Simulation/Engineering (PSS®E, Version 33) program from Siemens Power Technologies, Inc. (PTI). This program is accepted industry-wide for power flow analysis. Other software utilized in this analysis will include VSAT, POM/OPM, and PROMOD (if economic assessment is necessary).

Using the study criteria, PSS®E commands RATE and VCHK were utilized for documenting system characteristics under normal operating conditions. The ACCC and MCCC activities were used for documenting the system response to single and multiple contingency conditions.

For system intact or normal operating conditions, this study utilized the PSS®E RATE and VCHK activities to compare the thermal loadings and bus voltage against the thresholds identified in the Criteria section (Section A.3).

This study utilized the PSS®E ACCC activity to perform the single contingency simulations and compare the thermal loadings and bus voltage against the thresholds identified in the Criteria section (Section A.3).

This study utilized two methods in performing the multiple contingency analyses. This study first utilized the TARA software to perform a multiple contingency screening analysis. TARA software performed a comprehensive Category P6 (P6) analysis including all 69 kV and above transmission facilities within the study area. This screening analysis was used to identify the key multiple outage combinations to take forward to be simulated in the Project Need and Project Alternatives sections. The Need and Alternatives (Section 4) simulations utilized the PSS®E ACCC activity to perform the multiple contingency simulations and compared the thermal loadings and bus voltages against the thresholds identified in the Criteria section (Section A.3).

The key solution options chosen for performing the PSS®E power flow solution activity Fixed Slope Decoupled Newton-Raphson Solution (FDNS) are listed below.

- Tap adjustment - Stepping
- Switched shunt adjustment - Stepping
- Area interchange control – Line & Load
- Non-divergent solution - Disabled
- Phase shift adjustment - On

- DC tap adjustment - On
- VAR limits – Apply Immediately
- Newton tolerance – 1.0

The multiple outage analysis was conducted using the following four major steps.

- Step 1 – Perform TARA analysis for the study models to find critical contingencies which could cause potential system limitations.
- Step 2 – For the contingencies identified in Step 1, run ACCC activity in PSS®E and document system limitations.
- Step 3 – Develop list of potential solution options to mitigate limitations. Evaluate the performance of each of these solution options to determine which ones should be carried forward and developed as project alternatives.
- Step 4 – Compare system performance of all project alternatives identified in Step 3. Determine which alternative to select as the preferred solution for the system limitations identified in Steps 1 and 2.

Each of the project alternatives was evaluated to check for longevity or robustness by varying one or more of the project assumptions. For example, one of the robustness tests was to perform a prior maintenance plus tower contingency (prior plus Category P7) analysis on the shoulder models.

A.1.1 Mitigation Measures

Allowable mitigation measures such as the reconfiguration process outlined in Section 3.1.6 of the Project Scoping document were utilized as potential mitigation techniques in this analysis.

For NERC Category P1 contingencies, mitigation options were considered available to mitigate system limitations. MISO monitors the status of the system, continuously evaluates the impact of the next worst single contingency and pre-positions the system to protect against overloads and low voltages. Pre-positioning can include but is not limited to re-dispatching of generation and adjustment of flow control devices (i.e. phase shifters and BTB-HVDC). To replicate MISO's process for single contingency analysis, ATC's power flow simulations incorporated the potential mitigation options post-contingent to determine efficacy of eliminating system limitations. For prior maintenance plus NERC Category P1 scenarios, mitigation options were considered available to pre-position the system after the maintenance outage and prior to the single contingency.

For NERC Category single initiating events such as P2 or P7, mitigation options were only considered available post-contingency. The rationale behind this is that MISO will only pre-position the system for the next worst single contingency and does not consider

these contingencies in their pre-positioning process. For NERC Category P6 contingencies, mitigation options were considered available to pre-position the system after the first contingency and prior to the second contingency.

For the prior maintenance plus NERC Category P1 and P7 scenarios, mitigation options were considered to pre-position the system after the maintenance outage and prior to the second contingency. It should be noted that MISO will not pre-position under these scenarios. The only exception to this is when the MISO Tower Contingency Procedure RTO-RA-OP-004-r8 is activated during severe weather or threats of terrorism. MISO's semi-public procedure is activated for a particular tower under the following conditions:

- Tower contingency meets a minimum history requirement where the double contingency has occurred at least two times in a single 5-year period, and it was not due to equipment miss-operation, maintenance error, or vegetation issues.
- Credible double contingency can result in the separation, collapse, or island to a large geographical area where the amount of load at risk exceeds 300 MW.
- MISO will implement the credible double contingency upon verification that the criteria has been met for the Transmission Operator-identified credible double contingency, and MISO will only control to the credible double contingency until all planned upgrades necessary to mitigate the issue have been completed.
- The credible double contingency will be reflected as a single contingency event in the Transmission Planner's local planning guidelines or criteria at the next annual update of the criteria.

Reasonable load shed for NERC Category No Load Loss allowed contingencies is allowed, as long as the outage does not lead to instability, voltage collapse, voltage collapse due to cascading, or uncontrolled/unplanned loss of load to meet the requirements.

A.1.2 Contingencies Studied

The contingency analysis was performed in the study area as shown in Appendix B. The contingency analysis consisted of simulating NERC Category P1 through P7 contingencies on both the peak and shoulder models. Refer to Table A.2 for a listing of the contingencies simulated for this study.

For the summer peak models, NERC Category P1 through P7 simulated as listed in Table A.2. For the shoulder models, in addition to the before-mentioned contingencies, ATC performed prior outage or maintenance outage scenarios. These included select prior maintenance outages in combination with select Category P1 outages or select single initiating event outages (i.e. P7 common tower outages). The prior maintenance outage plus single initiating event outages were used to test robustness of the alternatives being considered.

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Table A.2
Contingencies studied

Category	Initial Condition	Event	Description
P0 No contingencies	Normal System	None	Within study area, all ATC transmission facilities will be monitored for overloads and voltage limitations.
P1 Single Contingency	Normal System	Loss of one of the following:	
		1. Generator	Within study area, include largest single unit on-line at any any multiple unit generating plant. Exclude all single unit generating plants less than 20 MW. Includes all event based contingencies.
		2. Transmission Circuit	All contingencies (no radials) within study area and all ties to study area greater than 100 kV. Includes all event based contingencies. Excludes eastern U.P. contingencies except for the Flow Control Device at Mackinac.
		3. Transformer	All contingencies within study area, high-side voltage greater than 100 kV. Includes all event based contingencies. Excludes eastern U.P. contingencies.
		4. Shunt Device	No P1.4 contingencies will be studied for MSC in the study area. The Benson Lake SVC contingency will be analyzed.
		5. Single pole (DC) line	No P1.5 contingencies will be studied. No HVDC lines within the study area or the ATC system.
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	No P2.1 contingencies will be analyzed.
		2. Bus Section Fault	
		3. Internal Breaker Fault (non-Bus-tie Breaker)	Select P2.2, P2.3 and P2.4 contingencies within the study area greater than 100 kV. Includes all event based contingencies.
		4. Internal Breaker Fault (Bus-tie Breaker)	Excludes eastern U.P. contingencies.
P3 Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following:	
		1. Generator	All generator plus generator combinations in the P1.1 contingency description.
		2. Transmission Circuit	All generators in the P1.1 contingency description plus all transmission circuits included in the P1.2 contingency description.
		3. Transformer	All generators in the P1.1 contingency description plus all transformers included in the P1.3 contingency description.
		4. Shunt Device	All generators in the P1.1 contingency description plus Benson Lake SVC.
		5. Single pole of a DC line	No P3.5 contingencies will be studied. No HVDC lines within the study area or the ATC system.
P4 Multiple Contingency (Fault plus stuck breaker)	Normal System	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following:	
		1. Generator	No P4.1 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		2. Transmission Circuit	No P4.2 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		3. Transformer	No P4.3 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		4. Shunt Device	No P4.4 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		5. Bus Section	No P4.5 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus	No P4.6 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.4 contingencies.

*Table A.2
Contingencies studied (continued)*

P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:	
		1. Generator	No P5.1 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		2. Transmission Circuit	No P5.2 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		3. Transformer	No P5.3 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		4. Shunt Device	No P5.4 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
		5. Bus Section	No P5.1 contingencies will be studied because from a steady state simulation perspective they are covered by the corresponding category P2.3 contingencies.
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System Adjustments:	Loss of one of the following:	
	1. Transmission Circuit	1. Transmission Circuit	All P.6 contingencies (no radials lines and non-SVC shunt devices) within the study area greater than 100 kV will be analyzed. Includes event based contingencies. Excludes eastern U.P. contingencies.
	2. Transformer	2. Transformer	
	3. Shunt Device	3. Shunt Device	
	4. Single pole of DC line	4. Single pole of a DC line	
P7 Multiple Contingency (Common Structure)	Normal System	Loss of one of the following:	
		1. Any two adjacent circuits on common structure	All P7.1 contingencies within the study area and ties to the study area with at least one circuit greater than 100 kV. Includes event based contingencies. Excludes eastern U.P. contingencies.
		2. loss of bipolar DC line	No P7.2 contingencies will be studied. No HVDC lines within the study area or the ATC system.

A.1.3 Monitored System

The major facilities of interest in this study are shown in Appendix C.

A.1.4 Magnetic Field Methodology

Per regulatory guidelines, system intact flows should be reported for 1-year post-construction of the preferred project and 10 years after the proposed in-service date. To be consistent with the analysis presented in Section 4, ATC utilized the 2026 Expected and power flow models. System intact ampere flows were provided to ATC's Engineering department so that the expected magnetic field levels could be calculated for the CPCN application. For the Howards Grove-Erdman study, these flows were calculated utilizing the 2024 Summer Peak and Off-Peak models from the MTEP 2019 cycle described in Section A.2.1.

Specific steps to determine system intact ampere flows were as follows:

- For 2024 analysis, run PSS@E LAMP activity under system intact conditions for the Summer Peak and Off-Peak Expected models.

- For 2033 models, ATC estimated the ampere flows by utilizing a 0.3% compounded growth rate with the 2024 models as a starting point. The growth rate was derived from the ATC-wide load forecast supplied by the LDCs in 2020.

ATC provided system intact line flow data for all transmission lines that could potentially affect magnetic field calculations including all transmission lines within 300' of each potential route of the preferred project as part of this analysis.

A.2 Assumptions

A.2.1 Models, Modeling Assumptions and Topology

For this study, all models were based on MISO's MTEP19 series models. These models were developed from the 2018 NERC Multi-Modeling Working Group (MMWG) model series, which prepares models for industry-wide use. The base models used for this analysis included:

- 2024 Summer Peak model
- 2024 Shoulder Off-Peak model
- 2029 Summer Peak model

ATC updated its footprint with the most updated topology, generation dispatch and the load forecast prepared by the LDCs in 2020, as described in the below sections.

The assumptions for studied scenarios are outlined in Table A.1 and consist of:

- Scenario #1: Edgewater Unit #5 offline
 - Edgewater unit #5 retired
- Scenario #2: Edgewater Unit #5 remains online
- Scenario #3: Other proposed area generation online
 - Holland Solar (J1153, 150 MW nameplate)
 - Per MISO methodology, 75 MW assumed online
 - Butternut Solar (J1171, 100 MW nameplate)
 - Per MISO methodology, 50 MW assumed online

Topology updates in the study area that may affect the needs that were included in all planning analyses:

- New Huebner: 2-8.16 MVAR capacitor banks (2021),
- New 20th Street: 2-8.16 MVAR capacitor banks (2021),
- Erdman 138/69 kV transformer replacement (2022), and
- X-48/Y-31 underground line rebuilds (2023).

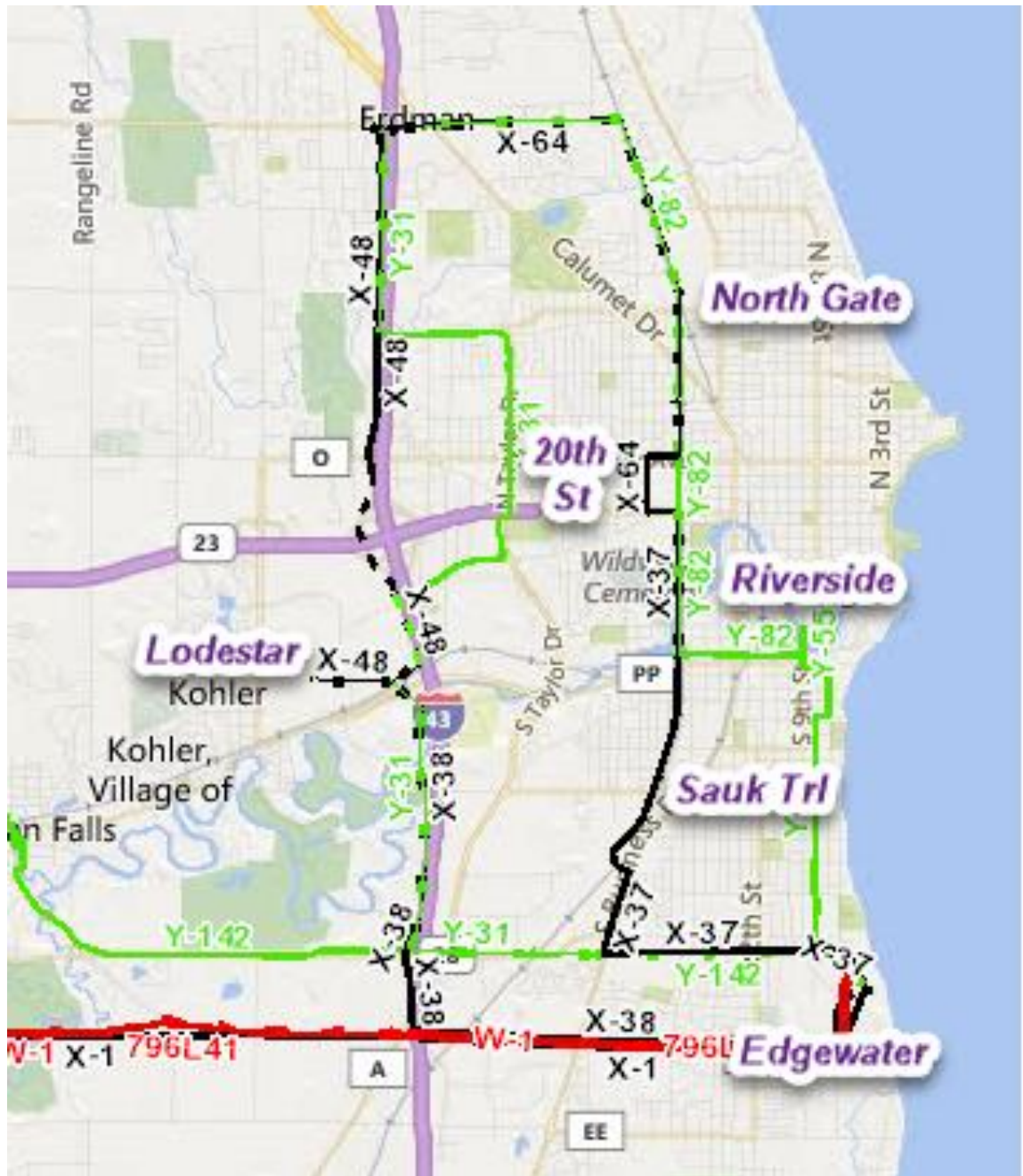


Table A.1: Model Assumptions for Howards Grove-Erdman 138 kV Line Project - Year 2024 Models							
	Edgewater offline scenario		Edgewater online scenario		Other proposed generation online		
	Summer Peak	Shoulder	Summer Peak	Shoulder	Summer Peak	Shoulder	Comments
Sheboygan area							
Edgewater generation	off	off	420.5 MW	420.5 MW	off	off	Edgewater unit #5 retired as of 6/1/22
Holland Solar (J1153)	N/A	N/A	N/A	N/A	75 MW	75 MW	per MISO methodology, dispatch 50% of nameplate
Butternut Solar (J1171)	N/A	N/A	N/A	N/A	50 MW	50 MW	per MISO methodology, dispatch 50% of nameplate

A.2.2 Study Methodology

Each of the study models were analyzed using PSS/E (Power System Simulator for Engineering), Version 34, an industry-standard application used in Transmission Planning analysis.

The PSS/E ACCC Contingency Solution application was used to apply all the appropriate contingencies to the study cases and monitor the study area for steady-state voltage or loading limitations.

Single (P1, P2, P3) and multiple-contingency (P6, P7) steady-state analysis was used in this study, with ATC Planning Criteria version 20 to be met for both steady-state voltage and thermal issues.

A.2.3 Load Forecast

The peak load forecasts included in study models within the ATC footprint were updated with the data supplied by the LDCs in 2019. Please refer to Appendix F for the detailed load forecast utilized in ATC's analysis.

The coincident load forecast represents the local distribution company forecasted loads at the time of their system's summer peak. As shown in Appendix F, the load in the study area has traditionally remained flat for the years 2012-2020. The load forecast indicates a 0.2% growth rate within the entire study area over the next 10 years (2021-2030).

The off-peak models (shoulder loading) were developed from the shoulder MISO models by scaling the scalable loads to 70% of their summer peak in the study area, which results in the loading being approximately 76% of the summer peak model load. This methodology is utilized as a result of historical data mining (shoulder vs. peak MW flows) of Pi Historian data for each affected area.

A.2.4 Generation Dispatch

The models dispatch generation by merit order and control area. Key generation in the study area included in ATC's models is shown in Table A.1.

A.3 Criteria

A.3.1. Study Criteria

NERC Transmission Planning Standard TPL-001-004 is generally applied to evaluate the transmission system. While NERC standards do not generally apply to ATC's 69 kV system, ATC Transmission Planning Criteria version 20 was developed to provide comparability across its system whether considering the Bulk Electric System (BES, 100 kV and above) or the non-bulk electric system (<100 kV). The ATC Planning Criteria was used to evaluate the ATC transmission facilities during the thermal and voltage analysis and is consistent with the NERC Standards in place when version 18 was developed.

ATC planning criteria pertinent to the justification and development of this project includes the following items.

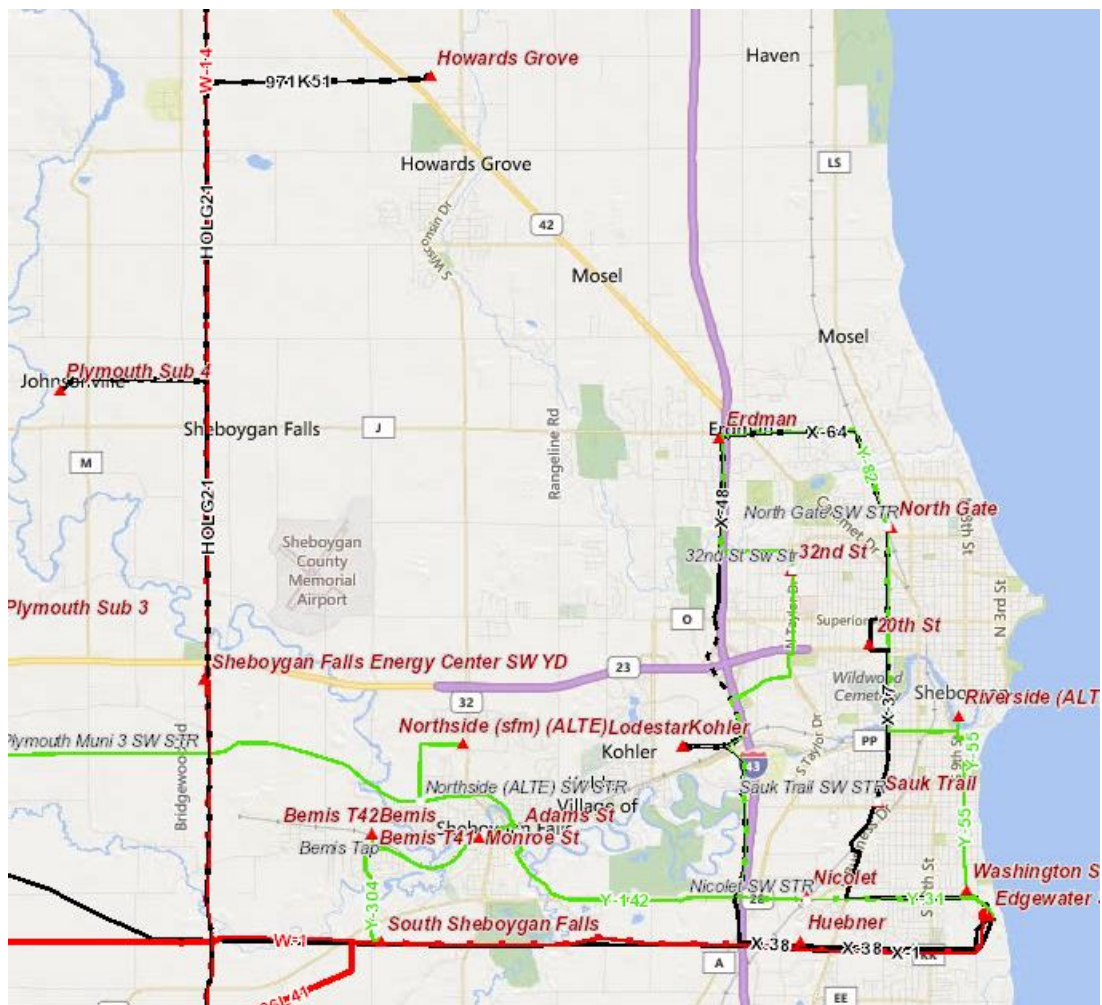
1. Thermal limitations of planning criteria were reported if branch loadings exceeded normal ratings under system intact conditions (NERC Category P0).
2. Thermal limitations were also reported if branch loadings exceeded emergency ratings under contingency conditions (NERC Categories P1 through P7).
3. Under system intact conditions, buses are monitored for voltages below 95% or above 105% of nominal (NERC Category P0).
4. Under post-contingency conditions, buses are monitored for voltages below 90% or above 110% of nominal (NERC Categories P1 through P7).

ATC's applicable planning criteria can be found at the following link:

<http://www.atc10yearplan.com/wp-content/uploads/2020/10/ATC-Transmission-Planning-Criteria-v20-Signed.pdf>

Voltage and angular stability analyses were not performed as part of this study due to minimal number of existing stability issues in the area.

Appendix B: Study Area



Appendix C: Existing System

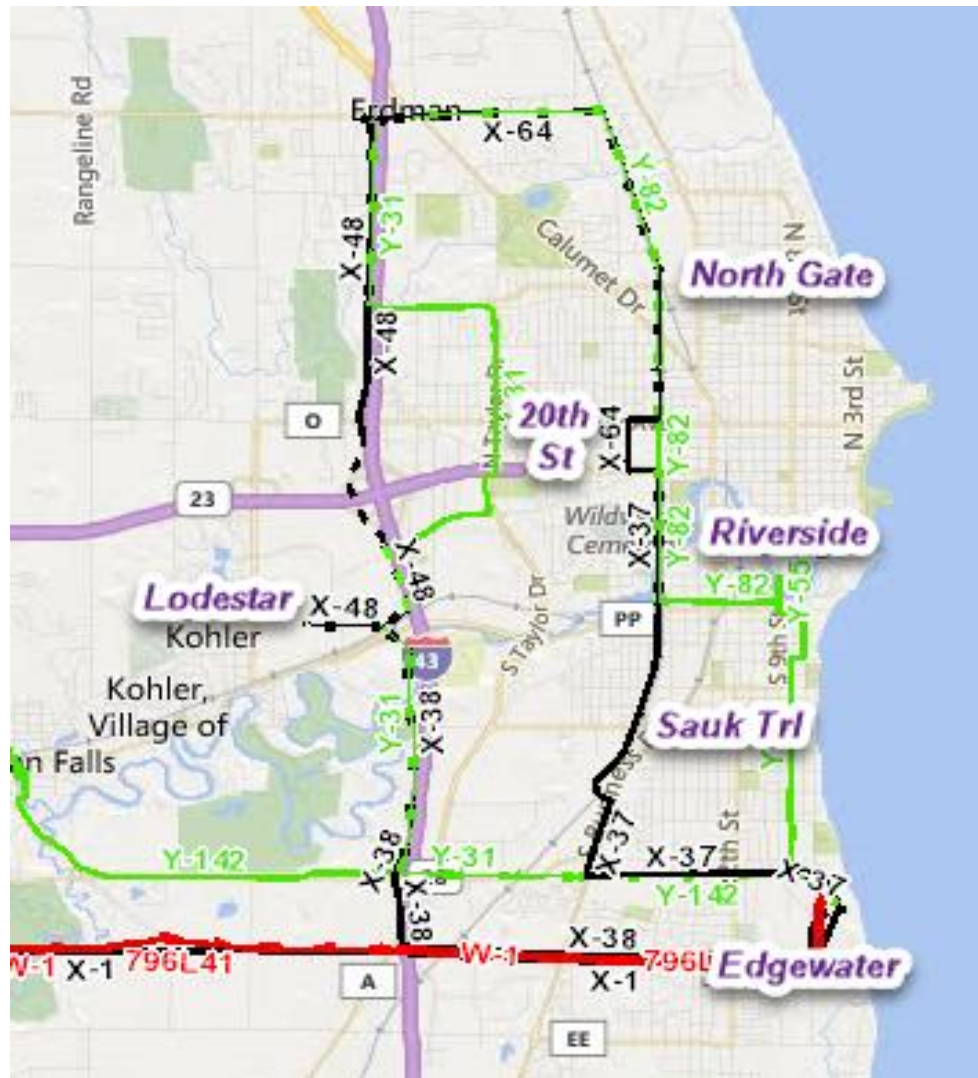


Figure C.1: Geographical area of transmission system

Appendix D: Project Diagrams





Appendix E: Needs and Alternatives Analysis

Table E.1: 2024 Summer Peak, Edgewater Offline Analysis

[illegible]

Table E.2: 2024 Shoulder, Edgewater Offline Analysis

[illegible]

Table E.3: 2029 Summer Peak, Edgewater Offline Analysis

[illegible]

Table E.4: 2024 Summer Peak, Edgewater Online Analysis

Date of simulations:	October, 2019						Needs		
Project name:	Howards Grove-Erdman Study								
Powerflow model:	2024 Summer, Edgewater online								
Modified powerflow model Includes:	Refer to Appendix A, Table A.1								
							NEEDS		
NERC Categories where Interruption of firm service is allowed							Expected	With Mitigation	
Table E.4: Category P6	(Loss of single element plus next event)		MVA Ratings				Emergency	Emergency	Normal
First Contingency	Second Contingency	Limiting Element	Norm/Emer		Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	43.9-81.1	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	74.4-75.0%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	88.5-88.9%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	Unsolved	>95%	>95%

Table E.5: 2024 Shoulder, Edgewater Online Analysis

Date of simulations:	October, 2019						Needs		
Project name:	Howards Grove-Erdman Study								
Powerflow model:	2024 Summer, Edgewater online								
Modified powerflow model Includes:	Refer to Appendix A, Table A.1								
NERC Categories where Interruption of firm service is allowed									
Table E.5: Prior Maintenance Outage (Prior Maintenance Outage + single outage, event based)							Edgeon Emergency	with mitigation Emergency	with mitigation Normal
Maintenance Outage	Contingency	Limiting Element	MVA Ratings Norm/Emer		Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	73.8-74.3%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	58.9-89.2%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	74-74.5%	>95%	>95%

Table E.6: 2029 Summer Peak, Edgewater Online Analysis

Date of simulations:	October, 2019						Needs		
Project name:	Howards Grove-Erdman Study								
Powerflow model:	2029 Summer, Edgewater online								
Modified powerflow model Includes:	Refer to Appendix A, Table A.1								
NERC Categories where Interruption of firm service is allowed							NEEDS		
Table E.6: Category P6 (Loss of single element plus next event)							Edgeon Emergency	With Mitigation	
First Contingency	Second Contingency	Limiting Element	MVA Ratings Norm/Emer		Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	44.2-81.4%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	86.0-86.5%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	89.3-80.7%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	Unsolved	>95%	>95%

Table E.7: 2024 Summer Peak, Sensitivity Analysis with Other Proposed Generation Online

Date of simulations:	June, 2020						Needs		
Project name:	Howards Grove-Erdman Study								
Powerflow model:	2024 Summer, Edgewater offline								
Modified powerflow model Includes:	J1173 Holland Solar generation and J1153 Butternut Solar generation								
							NEEDS		
NERC Categories where Interruption of firm service is allowed							Expected	With Mitigation	
							Sensitivity	With Mitigation	
Table E.7: Category P6	(Loss of single element plus next event)		MVA Ratings				Emergency	Emergency	Normal
First Contingency	Second Contingency	Limiting Element	Norm/Emer	Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V	
		Sheboygan area 138 and 69 kV bus voltages	N/A	Y	Y	49.4-89.4%	>95%	>95%	
		Sheboygan area 138 kV bus voltages	N/A	Y	Y	71.1-71.4%	>95%	>95%	
		Sheboygan area 138 kV bus voltages	N/A	Y	Y	86.3-86.7%	>95%	>95%	
		Sheboygan area 345, 138 and 69 kV bus voltages	N/A	Y	Y	unsolved	>95%	>95%	
		Sheboygan area 138 and 69 kV bus voltages	N/A	Y	Y	unsolved	>95%	>95%	
							Expected	With Mitigation	
Table E-7: Category P7	(loss of any two adjacent circuits on a common tower)		MVA Ratings				Emergency	Emergency	Normal
Tower Outage		Limiting Element	Norm/Emer	Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V	
		Sheboygan area 345, 138 and 9 kV bus voltages	N/A	Y	Y	unsolved	unsolved	unsolved	

Table E.8: 2024 Shoulder, Sensitivity Analysis with Other Proposed Generation Online

Date of simulations:	June, 2020						Needs		
Project name:	Howards Grove-Erdman Study								
Powerflow model:	2024 Shoulder, Edgewater offline								
Modified powerflow model Includes:	J1173 Holland Solar generation and J1153 Butternut Solar generation								
NERC Categories where Interruption of firm service is allowed									
Table E.8: Prior Maintenance Outage + Category P1 (Prior Maintenance Outage + single outage, event based)							Sensitivity	With Mitigation	
							Emergency	Emergency	Normal
Maintenance Outage	Contingency	Limiting Element	MVA Ratings Norm/Emer		Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	87.2-87.6%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	75-75.5%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	87.3-87.7%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	87.4-87.8%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	88.2-88.6%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	89.9-90%	>95%	>95%

Table E.9: 2029 Summer Peak, Sensitivity Analysis with Other Proposed Generation Online

Date of simulations:	June, 2020						Needs		
Project name:	Howards Grove-Erdman Study								
Powerflow model:	2029 Summer, Edgewater offline								
Modified powerflow model Includes:	J1173 Holland Solar generation and J1153 Butternut Solar generation								
NERC Categories where Interruption of firm service is allowed							Sensitivity	With Mitigation	
Table E.9: Category P6	(Loss of single element plus next event)		MVA Ratings				Emergency	Emergency	Normal
First Contingency	Second Contingency	Limiting Element	Norm/Emer		Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V
		Sheboygan area 138 and 69 kV bus voltages	N/A		Y	Y	50.8-89.5%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	76.7-77.1%	>95%	>95%
		Sheboygan area 138 kV bus voltages	N/A		Y	Y	88.2-88.6%	>95%	>95%
		Sheboygan area 345, 138 and 69 kV bus voltages	N/A		Y	Y	unsolved	>95%	>95%
		Sheboygan area 138 and 69 kV bus voltages	N/A		Y	Y	unsolved	>95%	>95%
Tower Outage		Limiting Element	Norm/Emer		Need?	Reinforce?	%RTG/V	%RTG/V	%RTG/V
		Sheboygan area 345, 138 and 69 kV bus voltages	N/A		Y	Y	unsolved	unsolved	unsolved

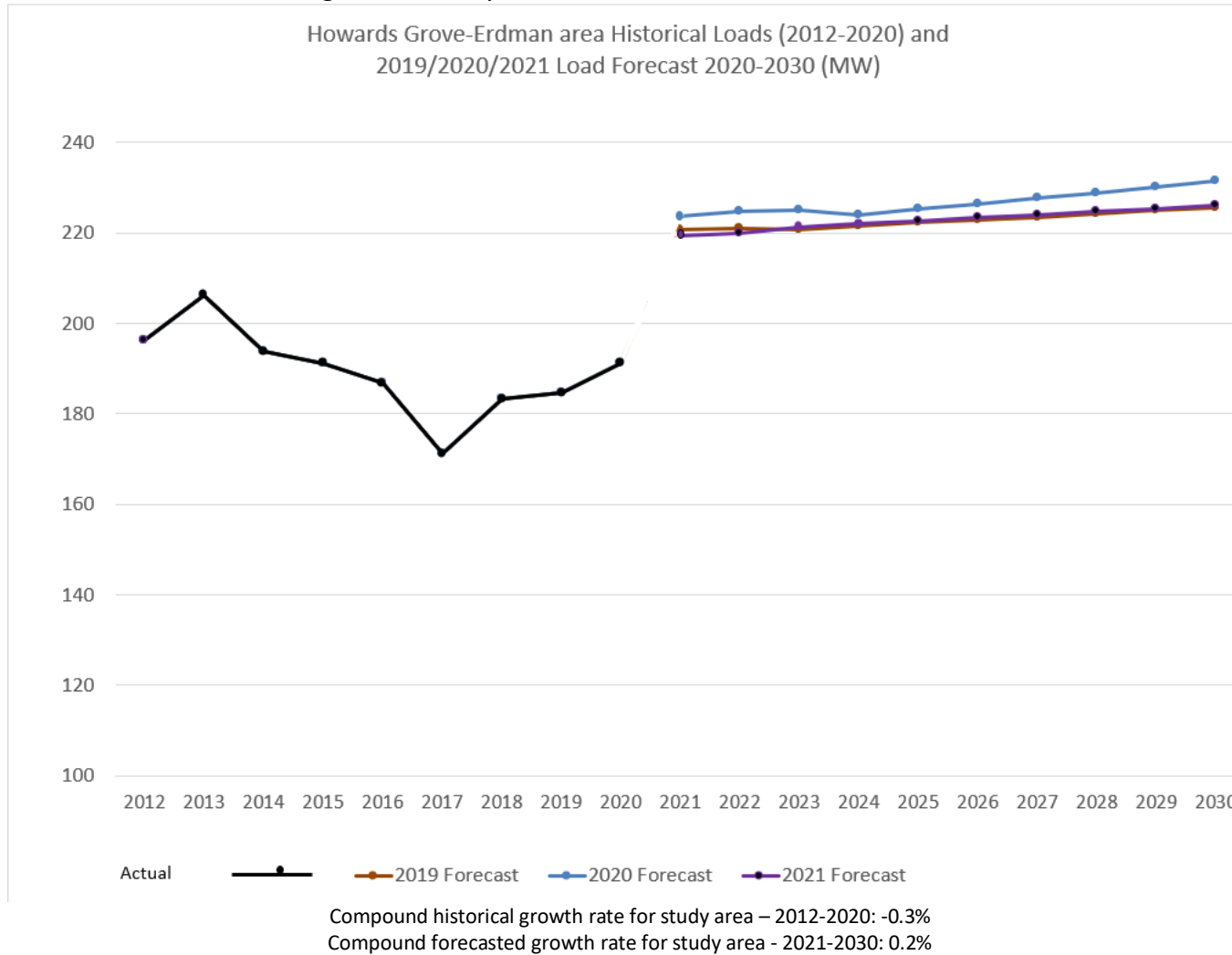
Appendix F: MW Load Forecast

The forecasted data was received from the Load Distribution Companies in 2019, and the historical data was received through the year 2020. In Figure F.1, historical loads and the forecast used in the Howards Grove-Erdman analysis was graphed in addition to the 2020 and 2021 load forecast data received from the LDCs.

Table F.1: Study Area Historical (2012-2020) and Load Forecast (2021-2030)

	2012 EDC Actual 7/17/12 @ HE15	2013 EDC Actual 8/27/13 @ HE16	2014 EDC Actual 7/22/14 @ HE17	2015 EDC Actual 8/14/15 @ HE16	2016 EDC Actual 7/22/16 @ HE17	2017 EDC Actual 6/12/17 @ HE15	2018 EDC Actual 6/29/18 @ HE17	2019 EDC Actual 7/19/19 @ HE17	2020 EDC Actual 7/7/20 @ HE15	Summer 2021 Forecast	Summer 2022 Forecast	Summer 2023 Forecast	Summer 2024 Forecast	Summer 2025 Forecast	Summer 2026 Forecast	Summer 2027 Forecast	Summer 2028 Forecast	Summer 2029 Forecast	Summer 2030 Forecast
Interconnection Point																			
	19.83	22.14	20.00	18.66	16.91	18.77	18.63	17.05	17.90	17.87	17.91	17.94	17.98	18.01	18.04	18.07	18.10	18.13	18.16
	13.43	13.00	12.00	11.70	11.90	9.10	10.80	12.60	12.05	10.36	10.38	10.40	10.42	10.44	10.46	10.48	10.49	10.51	10.52
	14.04	15.13	13.09	13.43	14.80	13.12	12.84	15.14	22.78	15.63	15.79	15.94	16.10	16.26	16.41	16.57	16.73	16.89	17.05
	16.22	15.84	14.52	14.50	14.61	14.80	11.41	12.60	12.91	12.77	12.84	12.90	12.96	13.03	13.08	13.15	13.21	13.27	13.33
	6.70	6.90	6.59	6.66	6.87	2.17	2.96	6.19	6.68	6.37	6.35	6.36	6.37	6.39	6.39	6.41	6.42	6.43	6.44
	14.71	13.30	14.36	15.37	14.83	13.61	14.92	10.11	0.00	9.42	9.47	9.52	9.57	9.61	9.65	9.70	9.75	9.79	9.83
	6.23	5.67	4.91	5.78	5.11	4.05	5.24	9.00	14.64	10.08	10.14	10.18	10.24	10.29	10.33	10.38	10.43	10.48	10.52
	4.80	4.87	5.07	4.97	5.47	3.40	6.44	6.70	7.25	6.33	6.39	6.45	6.52	6.58	6.65	6.71	6.78	6.84	6.90
	15.55	24.44	25.46	19.47	19.50	25.16	25.74	15.88	10.04	37.44	37.44	37.44	37.44	37.44	37.44	37.44	37.44	37.44	37.44
	6.60	6.60	7.99	7.37	8.61	8.28	3.08	4.33	6.61	8.14	8.18	8.22	8.26	8.30	8.34	8.38	8.42	8.46	8.50
	10.80	12.46	12.94	11.16	11.08	15.10	15.24	12.18	10.90	12.57	12.60	12.62	12.64	12.67	12.69	12.71	12.73	12.75	12.77
	16.42	16.90	13.48	14.74	12.72	13.36	13.45	13.47	16.93	15.17	15.20	15.23	15.26	15.29	15.31	15.33	15.36	15.38	15.41
	8.06	8.35	7.47	8.21	7.75	8.19	6.26	5.93	5.56	6.74	6.75	6.76	6.78	6.79	6.80	6.81	6.82	6.83	6.84
	10.58	10.56	8.66	9.47	8.31	6.51	7.05	7.84	8.70	8.60	8.62	8.63	8.65	8.66	8.68	8.69	8.71	8.72	8.73
	15.70	16.24	12.73	13.57	11.87		5.12	12.03	12.18	15.57	15.60	15.63	15.66	15.69	15.71	15.74	15.77	15.79	15.82
	0.00	0.00	0.00	0.00	0.00	0.00	1.82	2.27	2.56	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12
	0.00	0.00	0.00	0.00	0.00	0.00	4.95	4.68	6.40	9.20	8.62	7.65	7.65	7.65	7.65	7.65	7.65	7.65	7.65
	16.67	13.80	14.63	16.18	16.34	15.59	17.41	16.68	17.08	15.48	15.60	15.72	15.85	15.97	16.09	16.22	16.34	16.47	16.59
	196.3375	206.2101	193.9095	191.2193	186.6752	171.2077	183.3452	184.68	191.17	220.8198	221.0046	220.7223	221.464	222.1938	222.8467	223.5526	224.2462	224.9275	225.621

Figure F.1: Study Area MW Historical and Load Forecast



Appendix G: Megawatt Loss Analysis

Table G.1: Loss Comparison – 2024 Edgewater Retired Scenario

Study Model	Summer Peak model						Shoulder model					
	Study Area Gen.	Study Area Load	Study Area Import	Study Area Losses	ATC Losses	System Losses	Study Area Gen.	Study Area Load	Study Area Import	Study Area Losses	ATC Losses	System Losses
Original Model	0	223.9	224.7	0.8	265.4	16599.7	0	160.5	160.9	0.4	204.7	12850.8
With Alternative #1	0	223.9	224.5	0.6	265.1	16599.4	0	160.5	160.8	0.3	204.6	12850.8
With Alternative #2	0	223.9	224.6	0.7	265.1	16599.5	0	160.5	160.8	0.3	204.6	12850.8

Notes: All loss values in MW.

Notes: Original model – Refer to Appendix A for assumptions included in summer peak and shoulder scenarios.

Appendix H: Generation Alternatives



Howards Grove-Erdman 138 kV Area Project

New Generation Option Assessment

April 26, 2021

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System Planning

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1.0 Summary

ATC is proposing the Howards Grove-Erdman 138 kV line project with in-service date of 2023 to address identified needs. ATC recognizes that whenever a major transmission line project is proposed, a reasonable question to ask is whether non-transmission alternatives can avoid the need for the transmission reinforcement. This question has two major components:

1. Is a non-transmission alternative technically feasible, and
2. If technically feasible, is it a better method (considering cost, flexibility for the future, environmental impact, etc.) for addressing the need?

The study described in this document was intended to be a high-level screening for non-transmission, generation alternatives. This study considered whether additional generation capacity, if available, could be used to resolve and provide comparable benefits for reliability needs driving the Howards Grove-Erdman project identified by ATC's study of the planning study area. The study is based upon a similar methodology used in the Rockdale – West Middleton project and is focused on the reliability needs driven by facility outages in Wisconsin.

Approximately 75 MW of new generation each at the Edgewater and Erdman 138 kV sites for a total of 150 MW might provide comparable reliability benefits to the proposed Howards Grove-Erdman project depending on the future load and generation scenarios that develop. Angular stability analysis and short circuit analysis were not performed. These analyses are essential to the interconnection of a new generator, and often show that transmission system upgrades are required to support the generation addition. It also should be noted that a generation solution would not address the asset renewal concerns outlined in the Project Scoping Document.

This analysis also considered whether renewable forms of new generation might be cost competitive generation alternatives to address reliability needs related to the proposed transmission project. The available information shows renewable generation is not cost competitive.

ATC concluded that new generation does not provide a realistic alternative to the proposed transmission project. Moreover, no one is proposing to construct reasonable generation options to resolve the reliability limitations found in the planning study area, nor could generation be constructed on the timetable needed to address the identified reliability concerns.

2.0 Introduction

This study was intended to be a high-level screening of non-transmission, generation alternatives. The study sought to determine the minimum amount of new generation that would have to be built to provide comparable reliability results to the Howards Grove-Erdman project. To do this, ATC utilized a methodology that was developed as part of the Rockdale – West Middleton project. Various assumptions were utilized, which are outlined in the following sections.

2.1 Study Methodology

To perform this study, base models were taken from the Howards Grove-Erdman Project Scoping analysis and modified as described in this document. Two power flow models were created - the 2024 summer peak and shoulder modeling scenarios are referred to below as Scenario 1.

To obtain reliability results comparable to the Howards Grove-Erdman project, new generation was sited at Edgewater until the NERC contingency requiring the most amount of new generation to remove limitations was identified. NERC TPL Standards contingencies were applied to models with and without proposed mitigation options¹. If the contingency was a P6 or a prior maintenance plus Category P1 event, then the proposed mitigation options applied were accepted, as could be done in real time between the two contingencies. If the contingency was a Category P2 or P7 event, the results from the mitigation models were deemed not valid as the mitigation options couldn't be applied in real time.

The Edgewater 138 kV bus was considered to determine the amount of generation needed to mitigate the identified limitations. Generation was increased until the voltages in the study area were comparable to the voltages when the project is in

[REDACTED]

The worst contingencies for each case were applied to each model to find the lowest voltages in the study area. Then the contingencies were applied with the Howards Grove-Erdman 138 kV line in service and the area voltages became the target voltages to determine comparable generation size. Finally, the contingencies were applied without the Howards Grove-Erdman project and new generation increased until the area voltages were comparable to the voltages with the project in service.

¹ There are no feasible mitigation options for the P7 contingency studied and documented in this appendix.

ATC considered the peak and shoulder results for the 2024 model based upon the MTEP19 model series. In each scenario the highest generation value was selected from the peak and shoulder model results. The worst situation is represented by the highest new generation value needed to obtain comparable results. The minimum range of new generation needed became the lowest and highest worst situation values.

2.2 Assumptions

Loads

- 2024 Summer Peak and 2024 Shoulder Loads, 2019 vintage forecast
- Edgewater Offline Modeling Scenario defined in the Howards Grove-Erdman Project Scoping Document

Generation

- 2024 Summer Peak and 2024 Shoulder generation
- Edgewater units offline
- No other generation is available within the study area to address identified needs

Ratings

- ATC Study Based Rating Methodology ratings

NERC Contingencies Studied

Abbreviation	NERC Category	Full Description
[REDACTED]	P7	[REDACTED]
[REDACTED]	P6	[REDACTED]

Generation Addition Location

- For this high-level analysis, the Edgewater and Erdman 138 kV buses were the chosen sites.

Thresholds for comparable results

- The final generation addition amounts determined assume that, in the planning study area, the voltages on the equipment must be comparable to the voltages of the Howards Grove-Erdman 138 kV line alternative for system normal and contingency situations.

Software

- The study was conducted and performed in power flow software PSS/E v34 developed by Siemens Power Technologies, INC (PTI).

Approximate Cost of Proposed Transmission Project

- Construction – This study assumed the cost of the transmission reinforcement to be the planning level cost estimate as stated in the Bayport-Pioneer Project Scoping Document, \$21.6 million in 2023 dollars.
- Losses – This study assumed no significant difference because generation may only run when needed for impending system contingencies.

3.0 Analysis and Results

3.1 Generation Option – new generation at Edgewater and Erdman 138 kV buses

To assess the potential generation needed to offset the Howards Grove-Erdman line project, the decision was made to determine how much new generation would be needed to mitigate voltage limitations in the area such that voltages remain above 90% per unit post-contingency. To do this generation was first sited at Edgewater.

First, the contingency was applied to the base scenario models. Next, generation was modeled in 5 MW increments for each scenario until the new generation returned the system to comparable values of the proposed project.

The contingencies were applied with and without the Howards Grove-Erdman project in service. Area contingency voltages were compared to determine comparable generation size.



[REDACTED]

After the summer peak needs were determined, the off-peak shoulder condition was run with the worst contingency for that scenario. The worst contingency for the off-peak

[REDACTED]

Scenario 1 requires a minimum of 75 MW of generation in the peak model and 75 MW in the shoulder model to provide comparable benefits to the Howards Grove-Erdman project.

**Table H.1: Minimum New Generation Needed at Edgewater and Erdman
for Results Comparable to the Howards Grove-Erdman Project**

Scenario 1: Summer Peak					
Model	Contingency	Lowest voltage in Case	Area Voltages With Howards Grove-Erdman Reinforcement	Generator Size for Loading to be Comparable	Voltage on Facilities with new Generators
2024 Summer Peak with Edgewater offline		Edgewater 138 kV Erdman 138 kV	98% 97%	75 MW - Edgewater	98% 96%
2024 Shoulder with Edgewater offline		Edgewater 138 kV Erdman 138	100% 99%	75 MW - Erdman	100% 101%

Based on the scenario, a total of 150 MW was needed at Edgewater and Erdman (75 MW at each of two sites required to address both system peak and shoulder limitations) to provide comparable benefits to the Howards Grove-Erdman project.

4.0 Coal and Combustion Turbine Generation

4.1 Coal Cost Estimates

In the screening study, approximately 150 MW of generation located within the study area load pocket provides comparable reliability performance to the Howards Grove-Erdman. MISO's MTEP19 Appendix E2 provides stakeholder vetted cost and inflation assumptions (\$3.674/KW in 2019 \$, and 2.5%/year respectively) for the hypothetical installation of a Coal unit. Assuming two 75-MW generators installed in 2023, the total installed cost of \$608 million exceeds the cost of the proposed Howards Grove-Erdman project.

4.2 Combustion Turbine Cost Estimates

In the screening study, approximately 100-200 MW of generation located within the study area load pocket provides comparable reliability performance to the Howards Grove-Erdman project. MISO's MTEP19 Appendix E2 provides stakeholder vetted cost and inflation assumptions (\$899/KW in 2019 \$, and 2.5%/year respectively) for the hypothetical installation of a Combustion Turbine (CT). Assuming two 75-MW generators installed in 2023, the total installed cost of \$148 million exceeds the cost of the proposed Howards Grove-Erdman project. This analysis does not include the cost of the gas pipeline installation cost or the change in annual fuel and maintenance costs which would substantially increase the total CT generation alternative cost.

4.3 Coal and Combustion Turbine Availability

During the process of developing the Howards Grove-Erdman transmission project, ATC monitored the MISO Generation Interconnection Queue to evaluate whether there were any actively proposed generation alternatives which could be included in the reliability analysis for the project study area. There were no generation projects in the MISO Generation Interconnection Queue which provide alternatives for the proposed project.

4.4 Coal and Combustion Turbine Conclusions

The minimum amount of new generation ATC believes would be sufficient to provide comparable benefits to the Howards Grove-Erdman project in the study area is more expensive than the proposed project. The analysis does not attempt to value the gas pipeline installation cost or the change in annual fuel and maintenance costs which would substantially increase the total generation alternative cost.

Single cycle combustion turbine or coal generation are not viable options because they are more expensive and there are no generation projects in the MISO Generation Interconnection Queue as of April 2020 that could meet the reliability needs in the study area.

5.0 Renewable Generation

There has been no recent study performed for the study area to determine the amount of renewable generation that could be sited. If appropriate amounts could be sited, for new generation to provide benefits comparable to the Howards Grove-Erdman project it is estimated that 150 MW of new generation (75 MW at two different sites) would be needed within the Sheboygan area load pocket to provide comparable reliability benefits. The intermittent nature of some renewable resources would require additional capacity beyond the 150 MW. The following information presents cost information for combustible (biomass) and noncombustible renewable generation options (wind, solar, hydro) of this magnitude.

5.1 Combustible Renewable Generation

Biomass

According to MISO MTEP19 Appendix E2 – Electric Generation Expansion Analysis System (EGEAS) Assumptions Document, the expected installation cost for biomass is 3,860 \$/kW. Combustible renewable generation totaling 150 MW would cost approximately \$639 million in 2023 dollars. Operating and maintenance costs would add to overall costs.

5.2 Noncombustible Renewable Generation

Wind

According to MISO MTEP19 Appendix E2 – Electric Generation Expansion Analysis System (EGEAS) Assumptions Document, the expected installation cost for onshore wind is 1,505 \$/kW. Wind generation totaling 150 MW would cost approximately \$249 million in 2023 dollars. Operating and maintenance costs would add to overall costs. To the extent available, the Production Tax Credit incentive could be used to somewhat offset part of the annual carrying cost of the plant. Due to the intermittent nature of wind turbines the amount of generation needed to produce 150 MW would be substantially higher and add to the cost of such a solution.

Hydro

According to MISO MTEP19 Appendix E2 – Electric Generation Expansion Analysis System (EGEAS) Assumptions Document the expected installation cost for hydro is 3,830 \$/kW. Hydro generation totaling 150 MW would cost approximately \$634 million in 2023 dollars.

Photovoltaic

According to MISO MTEP19 Appendix E2 – Electric Generation Expansion Analysis System (EGEAS) Assumptions Document the expected installation cost for photovoltaic is 1,419 \$/kW. Solar generation totaling 150 MW would cost approximately \$235 million in 2023 dollars. Operating and maintenance costs would add to overall costs. To the extent available, the Investment Tax Credit incentive could be used to somewhat offset part of the annual carrying cost of the plant.

5.3 Renewable Generation Availability

During the process of developing the Howards Grove-Erdman project, ATC monitored the MISO Generation Interconnection Queue to evaluate whether there were any actively proposed renewable generation alternatives which could be included in the reliability analysis for the project study area. There were no renewable generation projects in the MISO Generation Interconnection Queue which provided alternatives for the proposed transmission project.

5.4 Renewable Generation Conclusions

The amount of renewable generation required to address reliability considerations within the study area is not cost competitive with the Howards Grove-Erdman project, costing anywhere from eleven to twenty-nine times more.

As the aforementioned information showed, none of the renewable options (biomass, wind, hydro and/or solar) could cost-effectively provide this capacity. Furthermore, no one is proposing to construct such generation on the timetable needed to address the reliability concerns, and even if they were, asset renewal requirements (as outlined in the Section 3 of the Project Scoping Document) would remain.